ANGDA

06-0406

Commercial Future of the Kenai LNG Plant

April 2006

Prepared by:

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April 18, 2006

Department of Revenue
Alaska Natural Gas Development Authority (ANGDA)
Attention: Harold Heinz, ANGDA
Contract Number: 06-0406
Project Name: Commercial Future of Kenai LNG Plant Evaluation
411 W. 4th Avenue
Anchorage
AK 99501

Dear Sirs:

Contract Number: 06-0406 Commercial Future of Kenai LNG Plant Evaluation

Shaw Alaska, Inc. and our affiliate, Stone & Webster Management Consultants Inc., (hereafter, collectively "Stone & Webster Consultants") are pleased to submit our Final Report to Alaska Natural Gas Development Authority ("ANGDA") on the evaluation of the commercial future of the Kenai LNG plant.

We trust that this report fulfills ANGDA's expectations. Should you require clarification or amplification of any of the issues covered by this report, please contact our Project Manager, Keith Darby, by email at keith.darby@shawgrp.com.

Yours truly
SHAW ALASKA, INC.

Laura Noland
Director

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AC	Alternating Current
ADCRT	Alaska Department of Culture, Recreation and Tourism
ADEQ	Alaska Department of Environmental Quality
ADHP	Alaska Division of Historic Preservation
ADNR	Alaska Department of Natural Resources
ADTD	Alaska Department of Transportation and Development
ADWF	Alaska Department of Wildlife and Fisheries
AEDD	Alaska Economic Development Department
ANGP	Alaska Natural Gas Pipeline
APCI	Air Products & Chemicals, Inc.
ASHRAE	American Society of Heating, Refrigeration and Air Conditioning Engineers
ASLO	Alaska State Land Office
ASTM	American Standard for Testing and Manufacturing
ºC	Degrees Centigrade
C3-MR	Propane Pre-Cooled Mixed Refrigerant
CADD	Computer Aided Design and Drafting
CAPEX	Capital Expenditure
CFD	Computational Fluid Dynamics
CGT	Combustion Gas Turbine
CH_4	Methane
CMMS	Computer Maintenance Management System
CO	Carbon Monoxide
CO_2	Carbon Dioxide
DC	Direct Current
DCS	Distributed Control System
DMR	Dual Mixed Refrigerant
DWT	Dead Weight Tonnage
EPA	Environmental Protection Agency
EPC	Engineering, Procurement and Construction
ESD	Emergency Shutdown
Fe	Iron
FEA	Finite Element Analysis
FEED	Front End Engineering Design
FID	Final Investment Decision
GE	General Electric
GJ	Giga Joules
H_2O	Water (or Steam)
H_2S	Hydrogen Sulfide
HAZOP	Hazards and Operability Analysis
HP	High Pressure
Hz	Hertz
IGCC	Integrated Gasification Combined Cycle
kV	kiloVolt
KPI	Key Performance Indicator
kVA	Kilovolt Ampere
LD	Liquidated Damages
LNG	Liquefied Natural Gas
LP	Low Pressure
LPG	Liquid Petroleum Gas

MJ	Mega Joules
Mlpd	Megalitres per day
tpd	Metric tonnes per day
tphr	Metric tonnes per hour
MCHE	Main Cryogenic Heat Exchanger
MP	Medium Pressure
MW	Mega Watt
N_2	Nitrogen
NDT	Non-destructive Testing
Ni	Nickel
NPV	Net Present Value
OCIMF	Oil Companies International Marine Forum
OSBL	Outside Battery Limits
P&ID	Piping and Instrumentation Diagram
PFD	Process Flow Diagram
PHA	Process Hazards Analysis
PJ	PetaJoules
PLC	Programmable Logic Controller
PMR	Propane Pre-cooled Mixed Refrigerant
PSA	Pressure Swing Absorption Unit
RAM	Reliability, Availability and Maintainability
RCA	Regulatory Commission of Alaska
S	Sulfur
SS	Stainless Steel
Ti	Titanium
TEAL	Technip/L'Air Liquide
TIC	Total Installed Cost
TJ	Tetra Joules
TMR	Triple Modular Redundant
TQM	Total Quality Management
QA/QC	Quality Assurance/Quality Control
UPS	Uninterruptible Power Source
USGC	United States Gulf Coast
US$	United States of America Dollar
V	Volt

The following table provides conversion factors for LNG in the units most commonly used to measure and define LNG. The liquid figures in the table are for pure methane at an atmospheric boiling point of minus 258.9°F (minus 161.6°C). The density of LNG at this temperature is 3.48 ponds per US gallon. The gas volumes are based on standard conditions 14.7 psia and 60°F. Heat equivalents are based on a higher heating value ("HHV") of 1,000 Btu per standard cubic foot of natural gas.

Conversion Factors for LNG

	Metric ton liquid	ft^3 liquid	m^3 liquid	Bbl liquid	Gal liquid	Scf gas	m^3 gas	Million Btu	Million Kilo calories
1 metric ton liquid	1	84.56	2.394	15.06	632.5	52,890	1,420	52.89	13.33
1 ft^3 liquid	0.01183	1	0.02831	0.1781	7.479	625.4	16.79	0.6254	0.1576
1 m^3 liquid	0.4177	35.32	1	6.29	265.4	22,090	593.1	22.09	5.567
1 bbl liquid	0.0664	5.615	0.1590	1	42	3,512	94.27	3.512	0.8850
1 gal liquid	0.001581	0.1337	0.003786	0.02381	1	83.62	2.245	0.08362	0.02107
1 ft^3 gas x 10^6	18.91	1,599	45.27	284.8	11,960	10^6	26,850	1,000	252
1 m^3 gas x 10^6	704.4	59,560	1,686	10,610	445,400	35.32 x 10^6	10^6	35,320	8,900
1 million BTU	0.01891	1.599	0.04527	0.2848	11.96	1,000	26.85	1	0.252
1 million kilocalories	0.07502	6.345	0.1796	1.130	47.46	3,968	112.4	3.968	1

1.1 OVERVIEW

Alaska Natural Gas Development Authority ("ANGDA") has appointed Shaw Alaska and its sister company, Stone & Webster Management Consultants, Inc. (collectively hereafter, "Stone & Webster Consultants") to provide a publicly available analysis of the Kenai LNG Plant owners' commercial considerations under a range of potential future operating scenarios.

Stone & Webster Consultants' scope of work comprised the following activities:

- Identify the technical and economic issues impacting the future operation of the Kenai LNG Plant;
- Identify potential orders of reduced operation or warm shut down (wherein system upgrades could be made) scenarios that would allow, in a timely manner, restart of the system upon successful tie-in to a long-term supply of gas;
- Indicate a pipeline routing and pipeline sizing from Palmer that would satisfy future Kenai needs;
- Evaluate the minimum timeframe in which the economics can be achieved.

The evaluation considered four potential operational outcomes. These were:

- Plant shutdown and removal;
- Conversion of the facility to an LNG receiving terminal;
- Continuation of current LNG export operations;
- Expanded plant facilities and expanded LNG export volumes to existing or new destinations.

As part of this evaluation, Stone & Webster Consultants has not considered the economic benefit of the continued operation of the Agrium fertilizer plant. Stone & Webster Consultants notes that, as a consumer of gas, in terms of economic benefit to the Kenai Peninsula, the Agrium plant would appear to be more beneficial than the Kenai LNG plant. It is on a larger plot and therefore pays more taxes, it employs significantly more people and consumes less gas. However, Agrium must purchase gas from local suppliers rather than monetizing its own reserves.

Stone & Webster Consultants concludes that the remaining useful life of the Kenai LNG Plant is of the order of six years without significant investment to modernize key elements of the plant. At present, the General Electric ("GE") Frame 5 combustion gas turbines that drive the compressors have class-leading operational lives. They have been in continuous service for 37 years. It is likely that these machines will require replacement in the next five years. Such a requirement is likely to initiate shutdown of the facility in its current form unless significant new gas reserves are made available to justify the investment in the continued operation or expansion of the facility. These new reserves could be in the Cook Inlet Basin or provided via a spur pipeline constructed from the North Slope gas transmission pipeline. In an ideal situation, sufficient natural gas would be available to warrant continued use and perhaps an increase in the capacity of the LNG Plant.

It should be noted that the economics of the life extension of the Kenai LNG Plant are to a certain extent dependent upon the ownership of the gas reserves and the LNG facility. In the current case, Marathon and ConocoPhillips are monetizing their gas reserves in the Kenai Basin through the production of LNG in a unified operation. However, in the case of a significant find by a third party, that party will have a number of options for monetization. It could:

- sell the gas to the local utility companies;
- sell the gas to the ConocoPhillips/Marathon joint venture;

- pay ConocoPhillips/Marathon to liquefy its gas on a tolling basis;
- sell the gas as feedstock to Agrium;
- sell the reserves as a whole to Conoco/Phillips, Agrium, and/or the local utility companies.

In a number of these scenarios, there will be at least three separate internal rate of returns ("IRRs") to satisfy, namely ConocoPhillips, Marathon and the gas supplier.

In the event that a new or increased gas supply is not available, the Kenai LNG Plant will either be shutdown (and possibly decommissioned) or it will be converted to another use. Stone & Webster Consultants expects this to occur before or during 2011. A number of potential uses exist for the facility that draw to a greater or lesser extent on its current facilities and function. Some of these may entail a change in ownership, since the economics may be different for an oil and gas multinational than for a local utility, especially if the utility is fully or partially-owned by the local municipality. Moreover, these different entities may be subject to different tax regimes. By way of example, while both ConocoPhillips and Marathon are actively involved in the importation of LNG into the USA, they may not be interested in such an operation if the offtake is limited to a local network, which is the case for South-Central Alaska.

Stone & Webster Consultants notes that ConocoPhillips is actively engaged in the development of the Freeport LNG terminal. This is located on the Gulf Coast of Texas. A new pipeline will connect the Freeport LNG facility to existing interstate pipelines that have a combined throughput of approximately five billion cubic feet per day. Thus the potential market for re-gasified LNG from the Freeport LNG Terminal is substantial, around 15 times that of the winter peak daily non-industrial demand for South-Central Alaska.

In Stone & Webster Consultants' opinion, it is unlikely that the Kenai facility will be converted to a peak shaving facility as there appear to be more cost-effective solutions in the immediate area, i.e. the use of existing gas reservoirs for gas storage. This is a well-established practice in the Lower 48 States and elsewhere in the developed world. Specifically, the Beluga River field currently supplies gas to Anchorage Municipal Power & Light and ENSTAR, the local gas utility. This reservoir would appear to be a good candidate for such an application. However, Stone & Webster Consultants has not undertaken an evaluation of the subsurface implications of this assumption.

A major advantage of using the Beluga River reservoir, should this be shown to be technically practicable, is that the existing gas distribution network is sized on the basis of this reservoir being the principal source of supply. Conversely, the use of the Kenai facility as a gas source would require reversing the existing gas-flow direction. This in turn would require an increase in the diameter of the pipeline serving parts of the current South-Central Alaska gas supply and distribution system. This can be achieved by replacing the existing system or augmenting sections with parallel lines, this is referred to as "looping". In addition, it would require regulation of the entire system to create a true grid in South-Central Alaska. While this issue is discussed in greater detail in Section 3.0 of this report, regulation allows access by multiple producers to the Gas Grid. Stone & Webster Consultants notes that pipelines built in Alaska since the enactment of the Alaska Pipeline Act are regulated and as such are common carriers. The Cook Inlet Gas Gathering System ("CIGGS") was built by Unocal Corp and Marathon Oil Co. prior to the enactment of this legislation and as such was unregulated. Unocal and Marathon reserved the capacity of CIGGS for the transportation of gas from their offshore fields to Agrium and Kenai LNG respectively. Agrium was in dispute with Unocal and Marathon over access rights to CIGGS for independent oil and gas operators who have discovered modest gas reserves want to use CIGGS to transport their gas to Agrium's plant at Nikiski on the Kenai Peninsula. In its Annual Report for 2005, the Regulatory Commission of Alaska ("RCA") reports that it issued Order P-04-20(5)/(U-05-20(3) on April 22, 2005 finding Marathon and Unocal to be public utilities under AS 42.05. However, it granted a comprehensive temporary exemption from regulation under AS 42.05 pending resolution of the docket. On May 11, 2005, the RCA issued an order granting Aurora Gas immediate interim access to CIGGS to transport gas from its Nicolai Creek unit.

In the event that additional gas reserves are not located in the Cook Inlet Basin and/or the North Slope Pipeline (together with a spur line to South Central Alaska) are not constructed in a timely manner, then it may be necessary to consider an alternative fuel source for South Central Alaska coupled with curtailment of current industrial use of gas. Options for an alternative fuel source include importation of LNG and/or liquefied petroleum gas ("LPG"). In either of these cases, the existing Kenai facility could be used as a supply terminal. However, before such a decision was made, a thorough analysis of the options would need to be undertaken. Again, by way of example, a LNG terminal might be better located near the Beluga River field so that full advantage could be taken of the existing gas distribution infrastructure. Kenai does, however, have several advantages as a LNG receiving and regasification terminal. These include:

- An existing LNG jetty;
- Three existing LNG storage tanks with a combined working capacity of 108,000 cubic meters;
- A large plot;
- Pre-existing utilities;
- LNG carriers sized relative to the storage capacity of the LNG tanks.

1.2 CONTINUED OPERATION

Over the years the LNG plant has undergone several debottlenecking expansions that have increased its liquefaction capacity to the current level of 220 MMscfd. This equates to approximately 3.5 million cubic meters or 1.45 million metric tonnes per annum of LNG exports, based on 350 days per year of onstream time (95 percent onstream availability). The decline of the Cook Inlet natural gas reserves, coupled with the end of the useful life of the Kenai plant after 40 years of operation, could very likely mean the end of LNG exports from Alaska. However, if the proposed new ANGP pipeline is constructed to monetize the substantial gas reserves in the North Slope area, and a new Spur Line branch from the ANGP pipeline is constructed from either the Fairbanks or Delta Junction to the Cook Inlet area, then continued operation of the LNG liquefaction plant could be viable. Previous studies regarding the Spur Line have indicated an initial capacity of 500 MMscfd, which approximates to the current Cook Inlet area average consumption rate. However, winter peak daily demand is purported to be as high as 800 MMscfd. Taking into account, the expansion in domestic demand, the Spurline should be sized for 1000 Mscfd to ensure year-round supply to domestic and industrial users.

Three integrated refrigeration systems are employed in the Phillips Optimized Cascade Process utilized at Kenai. In the Kenai LNG Plant, each of the three systems utilizes two 50 percent compressors, operating in parallel, with each individual compressor driven by a GE Frame 5 combustion gas turbine ("CGT"). ConocoPhillips refers to this as the "two-train-in-one' reliability concept whereby a single train of liquefaction heat exchangers are served by two compressors operating in parallel on each refrigerant. The advantage of this configuration is that downtime, scheduled or unscheduled, of a compressor and/or CGT driver does not result in total loss of production from the train. Thus a CGT can be taken out of service for a hot pass inspection without shutting down the plant as a whole. Moreover, over half of the train capacity is available provided that at least one compressor is running in each refrigeration loop. Depending on which compressor is down, adjustments in operating parameters can still enable the LNG

Plant to deliver up to 80 percent of its nameplate capacity. It is our understanding that the CGTs are now world-class leading in terms of years of continuous service. The longevity of these units is a major consideration in determining the remaining useful life of the plant as whole. It should be noted that there is a reduction in the efficiency of a CGT over time. From discussion with ConocoPhillips personnel, it is our understanding that this degradation is still well within the bounds of economic acceptability. Moreover, the rate of degradation is such that the Kenai LNG plant should be able to satisfy its contractual obligations through March 2009. While Stone & Webster Consultants has not been able to review the operational records for the Kenai LNG Plant, our expectation is that the residual life of the turbine/compressors may extend to the 2011 to 2014 period.

1.3 LNG EXPANSION

Following on from the previous discussion, if the proposed new ANGP pipeline and Spur Line branch are constructed, then continued and expanded operation of the LNG liquefaction plant could be viable. Contemporary baseload LNG plants typically have a capacity of at least 3.0 million metric tonnes per annum. By way of example, the Egyptian LNG Project built two trains of this size at Idku, near Alexandria in Egypt using the Phillips Optimized Cascade process. Feedstock requirements for such a train are of the order of 500 MMscfd, depending on gas composition. Previous studies regarding the Spur Line have indicated an initial capacity of 500 MMscfd, which approximates to the current Cook Inlet area average consumption rate. However, winter peak daily demand is purported to be as high as 800 MMscfd. Taking into account, the expansion in domestic demand, the Spurline should be sized for 1000 Mscfd to ensure year-round supply to domestic and industrial users in an expanded Kenai LNG scenario.

Increasing the annual capacity of the Kenai LNG plant to 3.0 million metric tonnes per annum will require new pre-treatment and liquefaction systems. In addition, Stone & Webster Consultants has assumed the need for additional LNG storage, namely a new 160,000 cubic meter capacity, full-containment LNG storage tank. Much of the existing support facilities and infrastructure, including the marine loading terminal, existing LNG storage tanks, and most of the buildings and utility systems will remain in use, albeit with some expansion of utility and support facilities. Stone & Webster Consultants estimates the capital cost of the expansion at US$1,200 million for the EPC Contract(s) plus US$300 million in separate Owners' Cost, for a total capital investment of US$1,500 million. This estimate incorporates a geographic cost adjustment factor for the Anchorage area of 1.4 times the equivalent US Gulf Coast cost.

Assuming a simple payout period of three years, the annual gross income or return on equity would be US$500 million per annum (1,500/3). Stone & Webster Consultants estimates annual fixed and variable operating costs for the new facility at approximately US$120 million per annum, or eight percent of the total installed capital cost, net of feedstock cost. On this basis, gross margin from LNG exports must be US$620 million per annum to satisfy the three-year simple payout criteria. This equates to a liquefaction plant LNG sales price component of approximately US$3.91 per thousand standard cubic feet ("Mscf"). A five-year simple payout would require a base LNG price of US$2.65 per Mscf. We note that gas is typically priced in terms of heating value, i.e., dollars per million British Thermal Unit ("Btu"). On the basis that we expect the calorific content of the gas to be of the order of 1000 Btu per scf, we have simplified the calculation to reference US$ per Mscf.

Project viability must consider the cost of gas supplied to the ultimate customer. Accordingly, Stone & Webster Consultants assumed a feed gas purchase price of US$2.50 per Mscf and a further US$1.50 per Mscf in the aggregate for pipeline tolls, shipping costs to the Canadian or US west coast, and terminal fees for receiving, regasification, and pipeline export natural gas to the customer. This results in west coast delivered gas prices of US$7.91 and US$6.65 per Mscf, respectively for the three-year and five-year simple payout cases. These sale values are comparable to the average February 2006 Henry Hub (Louisiana) price of approximately US$7.52 per Mscf. Therefore, there is little price adjustment available to increase the base purchase price of the North Slope natural gas price to recoup ANGP and Spur Line pipeline investment and operating costs to deliver North Slope gas to the new Kenai liquefaction facilities, and ultimately into the U.S. west coast market.

A more conventional economic analysis of the proposed expansion would be a calculation of the projected cash flow pro forma, including depreciation and U.S. federal income taxes. Two cases have been evaluated, based on gross revenue required for a three-year simple payout and for a five-year simple payout. The actual after-tax payout period for the three-year case is 4.1 years, which equates a Book Value Rate of Return of 24.5 percent, which is a good return on equity. The five-year case results in an actual after-tax payout period of 6.3 years and a Book Value Rate of Return of 15.8 percent. This latter case is likely to be closer to the projected economic performance considered to be acceptable to the Kenai plant owners, assuming the owners will provide all equity contributions and financing. However, as an entity of the State of Alaska, ANGDA can utilize tax-free bonds to finance the Project, making even longer equivalent payout periods economically viable.

1.4 LNG RECEIVING TERMINAL

Whether the Kenai LNG plant undergoes a minimal conversion to a peak shaving facility or a more substantial conversion into a LNG receiving and regasification terminal would most likely depend upon whether the proposed Spur Line will be constructed.

In the case of a LNG Receiving and Regasification Terminal, the modifications to the existing Kenai Plant would include the provision of a bank of vaporizers to regasify the LNG and sendout pumps. Stone & Webster Consultants would expect the vaporization and sendout capacity to be based on projected peak winter demand for residential and commercial consumers in terms of both electricity generation and gas distribution – say 500 MMscfd, including an allowance for growth. However, this demand is not constant over the course of a day. Typically, peak hourly demand will occur around 4pm to 6pm as people return from work, boost heating and start cooking the evening meal. We would expect the design of the facilities to keep one vaporizer in reserve at all times. This is generally referred to as "n+1" sizing where "n" is the number required to satisfy demand. Assuming a maximum hourly rate of 25 MMscfh, the equivalent daily rate upon which vaporizers are sized is 600 MMscfd. This equates to four 150 MMscfd vaporizers, i.e. in this case "n" equals four and so including the reserve equipment, five such vaporizers would be provided. During the engineering phase of such a project, the life-cycle economics would typically compare the relative costs of five 150 MMscfd units and six 125 MMscfd units. While the latter may involve additional capital costs it would provide greater flexibility in meeting a wide range of delivery requirements which could be beneficial over the life of the plant.

Stone & Webster Consultants has assumed that the conversion of the Kenai baseload LNG plant to a LNG receiving and regasification terminal would include the installation of new in-tank transfer pumps in each of the three existing LNG storage tanks at an installed cost of US$4.0 million. Regasification would be entail the addition of new regasification units operating in parallel, with each parallel unit consisting of a high-pressure send-out pump and a submerged combustion vaporizer. The total installed cost for these units is assumed to be of the order of US$33.0 million. The cost for the new send-out metering station, high-voltage switchgear, water neutralization and disposal facilities, re-location of the existing vapor return blower, plus additional miscellaneous piping, instrumentation, etc. is assumed to add a further US$13.0 million. Thus the EPC Contract cost for the receiving and regasification terminal conversion is estimated at US$50.0 million. Owners' costs equivalent to 25 percent of the EPC Costs, or US$12.5 million, would yield a total Project capital cost estimate of US$62.5 million.

Based on previous experience, Stone & Webster Consultants estimates the operations and maintenance ("O&M") cost for the converted facilities at approximately US$14 million per annum. The gross revenues, from a tolling fee of US$0.45 per Mscf are US$32,850,000 per annum, based on the average annual send-out rate of 200 MMscfd. After covering the annual O&M cost, the net revenues are US$20,850,000 per annum. Application of these net revenues toward the total Project capital cost of US$62.5 Million results in a simple payout period of three years. This equates to the analysis applied to the previous commercial options for conversion of the Kenai LNG plant, which were also based on a three-year simple payout analysis. Therefore, Stone & Webster Consultants would conclude, based on this preliminary analysis, that this option would appear to be economically viable.

In support of this analysis, the gas sales revenue and the exported gas sales price can be built-up to provide for a three-year simple payout period as before. To illustrate, the exported gas volume of 200 MMscfd equates to 73,000,000 Mscf per annum. The estimated annual O&M cost of US$12,000,000 per annum thus results in a unit O&M cost of US$0.165 per Mscf. In order to meet the 3-year payout requirement, revenues must also include US$20,833,333 per annum (US$62.5 million/3), which equates to US$0.285 per Mscf. Assuming an imported LNG cost of $5.00/Mscf, the gross sales price required to satisfy a three-year simple payout and meet O&M cost obligations is thus US$5.45 per Mscf (5.00 +0.165 + 0.285).

Thus for comparison purposes, the unit O&M cost assessment plus the unit return on equity assessment together equal the US$0.45 per Mscf tolling fee. Therefore the overall economic assessment approach utilized herein is consistent and rational. The calculated exported gas sales price of US$5.45 per Mscf over the LNG purchase price of US$5.00 per Mscf is thus a reasonable amount, and this same tolling fee can also be utilized to examine higher costs for imported LNG and the resultant exported gas sales price, as well as increased LNG receiving and regasification capacity scenarios.

1.5 LPG TERMINAL

Construction of the Spur Line or incorporation of LPG removal facilities at the Fairbanks or Delta Junction and transportation of the mixed liquids to Kenai opens opportunities for the location to be converted to an LPG fractionation and export terminal. In the case of a LPG Terminal, the advantages of the Kenai Plant include:

- An existing LNG jetty;
- Three existing LNG storage tanks with a combined working capacity of 108,000 cubic meters;
- Existing propane and ethylene storage tanks;
- A large plot;
- Pre-existing utilities;

The new Kenai fractionation plant would fractionates the mixed LPG feed in a depropanizer tower, producing propane product as the distillate or overhead product. Bottoms product from the depropanizer would feed the new debutanizer tower. A mixture of isobutane and normal butane would comprise the distillate product stream, and a light natural gasoline stream would comprise the bottom product from the debutanizer. Existing utility systems would be utilized to support the new product fractionation facilities, including fuel gas and cooling water, etc. Additional utility system investment should be minimal.

No further product treatment is anticipated for any of the fractionation plant products as a result of the low sulfur content of the mixed LPG fractionation plant feed stream, and because they would be fully dehydrated. However, the light gasoline product stream will have a true vapor pressure of approximately 13.3 psia, so it likely should be stored in a new pressurized 10,000 barrel spherical storage tank. The use of such pressurized storage provides environmental protection and contains the vapor pressure natural gasoline products.

Propane and butane products could be stored in the existing Kenai LNG storage tanks. A new, closed-loop propane refrigeration system would be installed to cool the propane and butane products to their atmospheric storage temperatures prior to entering the tanks, and to condense the respective boil-off gas streams. Two of the three existing LNG storage tanks could be allocated to propane storage, with the third tank utilized for butane storage. Each of the LNG storage tanks has a capacity of 225,000 barrels. Therefore depending on the exact mixed LPG feedstock composition, two tanks would provide approximately eight days of propane storage, which should be adequate for shipping logistics. The third tank would provide almost 37 days of storage for the butane product, which is much more than required.

An order of magnitude capital cost for the new LPG Fractionation Plant, plus other expected plant revisions, at Kenai would be approximately US$200 Million.

1.6 SUMMARY

Table 1.6-1 provides a comparison of the options considered by Stone & Webster Consultants.

Table 1.6-1
Comparison of Options

Option	Capital Cost Estimate (US$ Millions))	LNG/Gas Sales Price for Three-Year Payout (US$)
Continued Operation	**300**	**6.1**
Expansion to 3.0 MMmtpa	**1,500**	**7.9**
Traditional Peak Shaver	**125**	**22.6**
Imported LNG Peak Shaver	**50**	**13.8**
LNG Regasification Terminal	**63**	**5.5**
LPG Terminal	**200**	**N/A**

1.7 CONCLUSIONS

The natural economic life of the Kenai LNG plant is nearing its end. Provided that an export license can be obtained, and additional reserves obtained to justify continued operation, then the plant could operate through 2011 and perhaps beyond that date albeit with decreasing availability/reliability. This mode of operation could potentially support spot sales of LNG.

Robust and continuous operation of the Kenai LNG plant beyond 2011 will require significant investment. This investment will in turn require a guaranteed source of gas for at least a 15-year period. As a minimum, major elements of the plant would be replaced on a like for like basis. More likely, the plant would be upgraded and optimized, possibly increasing the capacity of the plant to three million metric tonnes per year of LNG. In this instance, additional investment would be required in the LNG carrier fleet too.

Unless a timely decision is made to construct the ANGP and associated Spur Line, such that gas can be delivered to the South-Central Alaska area by 2014, then the area will be deficient in gas. In this instance, the Kenai LNG plant could be converted to use as a LNG receiving and regasification terminal at the end of its natural life as a baseload LNG plant. This change of use may be associated with a change of ownership. It may be appropriate for one or more of the local utilities to purchase the plant, undertake the conversion and operate the plant as part of an integrated gas grid serving South-Central Alaska.

2.1 PREAMBLE

In 1967 Phillips Petroleum Company and Marathon Oil Company, as the Kenai LNG project developers and LNG exporters, executed a LNG sales agreement with LNG off-takers Tokyo Gas Company, Ltd. and Tokyo Electric Power Company, Inc. The Kenai LNG plant has been in continuous service since 1969. The facility has been expanded twice to a present capacity of 1.57 million tonnes per year. It was originally designed to liquefy 172.6 MMscfd of stranded natural gas produced from nearby Cook Inlet area gas production fields. The term "stranded gas" refers to the lack of a local market sufficiently large to justify the cost of gas exploration, drilling and production. This lack of a sufficient local market led to the decision to build the LNG liquefaction plant to export LNG to monetize the overall natural gas development expenditures. The original sales contract was for a term of 15 years with options to extend for an additional five years.

At the time, the Kenai LNG Project was the world's largest LNG project, and also up to that time, it was the largest project in the history of both Phillips and Marathon. Phillips (now ConocoPhillips) has a 70 percent ownership in the project and responsibility for operation of the plant. Marathon has the remaining 30 percent interest in the plant and is responsible for operation of the two LNG carriers that transport the LNG to Japan. The plant was the first commercial application of the Phillips Optimized Cascade LNG technology, which utilizes three separate refrigeration cycles, propane, ethylene, and methane loops, configured in series operation. Over the years the LNG plant has undergone several debottlenecking expansions that have increased its liquefaction capacity to the current level of 214 MMscfd. This equates to approximately 3.5 million cubic meters (1.55 million metric tonnes) per annum of LNG exports, allowing for 350 days per year of onstream time (95 percent onstream availability).

The two original LNG tankers, "Polar Alaska" and "Arctic Tokyo," each with a cargo capacity of 71,500 cubic meters, began LNG transport service in 1969, and remained in service until 1993. They are still in operation currently in alternate service as the "Methane Polar" and the "Methane Arctic." In July and December 1993 these original tankers were replaced with the 87,500 cubic meter "Polar Eagle" and the Arctic Sun." Like their predecessors, they were designed for rough weather and cold temperature service. For several months of the year the Cook Inlet is covered in broken ice. The LNG tankers have ice reinforcement to the hull, propeller, shafting, and gearing. Each round trip requires approximately 18 days, and each LNG tanker makes 20 round trips per year. Thus, the combined transport capacity of both 87,500 cubic meter tankers is just sufficient to deliver the 3.5 million cubic meters of LNG production from the Kenai plant.

By 1989 following the end of the original LNG sales contract and extension, a new contract was negotiated, which extended through 2004, with an extension through 2009, the current end of the sales agreement. The decline of the Cook Inlet natural gas production, coupled to considerations of the remaining useful life of the Kenai plant after 40 years of operation, may mean the end of LNG exports from Alaska.

Several options are being considered regarding the commercial future of the Kenai LNG plant. The Kenai LNG liquefaction plant is currently supplied with natural gas feed from reserves in the Cook Inlet oil and gas production fields. According to the South-Central Alaska Natural Gas Study[1], the original recoverable gas reserves from the Cook Inlet area are of the order of 8.4 trillion standard cubic feet ("tscf"). The Alaska Department of Natural Resources reports annual production during 2004 and 2005 to be 208 billion cubic feet per year. Remaining proven reserves as of January 1, 2006 were 1.6 tscf.

During 2003, average daily consumption of natural gas was 548 MMscf, comprising 214 MMscfd by the Kenai liquefaction plant, 142 MMscfd by the Agrium ammonia and urea fertilizer plant, and 192 MMscfd by residential and commercial consumers. Production-based consumption is of the order of 40 bcf per annum. Based on [1], assuming the Agrium plant is shut down in 2006 due to the lack of feed gas at an economically viable price and the Kenai LNG plant is shut down coincident with conclusion of its export contract in 2009, the pre-existing gas reserves are only able to sustain the current residential and light commercial demand through 2012. Trending recently discovered new reserves indicate that conventional natural gas production from the additional new and probable future reserves could satisfy the projected residential and light commercial demand until approximately 2025, but this is not proven.

Large seasonal swings in gas demand and the possibility that new additional gas discoveries do not come to fruition in the required timeframe suggest that the State of Alaska should consider other options for the commercial future of the Kenai LNG Plant that secure gas supply to the population of South-Central Alaska. One of the potential options might be the conversion of the liquefaction plant to a LNG peak shaving facility, which would help normalize the large swings in seasonal demand. Another option might be the conversion of the liquefaction plant to a LNG receiving and re-vaporization terminal, whereby LNG is imported and re-vaporized to meet the natural gas demands of the future, both peak seasonal demand and continuous base-load demand. However, if the proposed new ANGP pipeline is constructed to monetize the large gas reserves in the North Slope area, and if a new Spur Line branch from the ANGP pipeline is constructed from Fairbanks to the Anchorage area, then a new or expanded LNG liquefaction plant could be constructed at Kenai allowing LNG exports from Alaska to continue or resume. This continued operation of this plant may be a key driver in the economic assessment of the supply of North Slope gas to the Cook Inlet area. Assuming a three million metric tonne per annum LNG plant, this would require approximately 455 MMscfd of feed gas to produce seven million cubic meters per annum of LNG exports. Such a quantity of gas would essentially baseload the Spur Line and assist in providing North Slope gas to South-Central Alaska at an affordable price. The assumed size of the new plant is essentially double that of the existing plant, but at the lower end of the range of plants that are currently being built. Depending on the market that this LNG supplies, this may also require doubling the existing storage and/or shipping capacity.

ANGDA has appointed Shaw Alaska and its sister company, Stone & Webster Management Consultants, Inc. (collectively hereafter, "Stone & Webster Consultants") to provide a publicly available analysis of the Kenai LNG Plant owners' commercial considerations under a range of potential future operating scenarios. In considering the course of action that the plant owners may take, Stone & Webster Consultants has considered that public companies actions are accountable to their shareholders and there is an underlying responsibility to improve shareholder value. While a given project may be economically attractive, it will be measured against other opportunities in the company's portfolio.

This report examines various options relating to the commercial future of the Kenai LNG Plant.

2.2 SCOPE OF WORK

Stone & Webster Consultants' scope of work comprised the following activities:

- Identify the technical and economic issues impacting the future operation of the Kenai LNG Plant;
- Identify potential orders of reduced operation or warm shut down (wherein system upgrades could be made) scenarios that would allow, in a timely manner, restart of the system upon successful tie-in to a long-term supply of gas;
- Indicate a pipeline routing and pipeline sizing from Palmer that would satisfy future Kenai needs;
- Evaluate the minimum timeframe in which the economics can be achieved.

The evaluation considered four potential operational outcomes. These were:

- Plant shutdown and removal;
- Conversion of the facility to an LNG receiving terminal;
- Continuation of current LNG export operations;
- Expanded plant facilities and expanded LNG export volumes to existing or new destinations.

3.1 OVERVIEW

This section of the report discusses the history of hydrocarbon development in the Cook Inlet and the current situation with respect to remaining reserves. A detailed analysis of this topic can be found in the South-Central Alaska Natural Gas Study, Final Report, June 2004 [1]. The Cook Inlet Basin provides all of the natural gas used in south-central Alaska. Within South-Central Alaska, natural gas has three principal uses:

- Utility gas for residential and commercial consumers;
- Fuel gas for the generation of electricity;
- Feedstock for industry, specifically, Agrium's fertilizer plant and the ConocoPhillips/Marathon owned liquefied natural gas plant, both located at Nikiski on the Kenai Peninsula.

At current demand rates, the proven reserves in the Cook Inlet are adequate for another eight years of supply, however, the production decline curve is such that production will continue until around 2035 but non-industrial demand will exceed annual production after 2013, see Figure 3.1-1. Thus, an improvement in proven reserves, a reduction in demand and/or a replacement source of natural gas will be required in the medium term to support the energy needs of South-Central Alaska.

3.2 HISTORY

The oil and gas industry in the Cook Inlet has a long history. Oil seeps on the Iniskin Peninsula were noted by Russian explorers as early as the 1850's. Photographs show wooden derricks being used for oil exploration in the general area circa 1900. Initially, exploration wells were drilled near seeps.

The first commercial oil discovery, the Swanson River field, was made by Richfield Oil in July 1957. Production from the field commenced in 1958. The largest Cook Inlet oil field, the McArthur River field, containing 1.5 billion barrels of crude oil, was discovered in 1965. Exploration peaked in the second half of the 1960's. Later discoveries include the Sunfish/Tyonek Deep field in 1991. Today, world class land-based drilling rigs are used to explore for oil. Current oil producers in the Cook Inlet include Unocal (Chevron), XTO and Forest Oil.

Annual oil production peaked in 1970 at 82 million barrels. There has been a steady decline in oil production from the Cook Inlet such that in 2002 oil production was 11.5 million barrels. Production to date of crude oil exceeds 1.3 billion barrels. Proven remaining reserves are of the order of 180 million barrels.

Natural gas was discovered during exploration for oil in the 1950's. The Kenai field, the first and largest commercial gas field in the Cook Inlet, was discovered by Union Oil of California ("Unocal") in 1959. Cook Inlet gas production commenced in 1961. Only Cannery Loop, the smallest of the 10 largest gas fields in the Cook Inlet was discovered by exploring specifically for natural gas. This was in 1979. Notably, of the 267 exploration wells drilled in the Cook Inlet through 2002, only 24 were natural gas exploration wells. The reason for this is discussed in Section 3.3. Historically, the main natural gas producers in the Cook Inlet were Unocal, Chevron, Marathon and ConocoPhillips. More recently, a number of new entrants have entered the gas production and supply market in the Cook Inlet Basin. These include: Northstar Energy, Forest Oil, Aurora, XTO Energy and Escopeta. Appendix B identifies their websites.

Annual natural gas production peaked in 1994 at 311 billion cubic feet. As with crude oil, there has been a steady decline in annual gas production over time. In 2005, net gas production was 208.8 billion cubic feet. Production to date exceeds 6.8 trillion cubic feet. Proven remaining reserves are of the order of 1.6 trillion cubic feet.

Much of the Cook Inlet hydrocarbons are produced from 16 offshore platforms. Typically such production is six times more expensive than equivalent land-based production.

It is Stone & Webster Consultants' understanding that until recently there has been little incentive to increase proven gas reserves in the Cook Inlet since these would effectively be stranded, i.e., without an immediate point of sale from which to recover development costs. By 1970 the vast majority, about 8.0 out of the current 8.5 trillion cubic feet of current known recoverable gas had been discovered. This represented a considerable oversupply for the then current local demand of 167 billion cubic feet per year. The reserves-to-production ratio was 50, i.e., existing reserves were able to supply local gas consumers – industrial, power and domestic for 50 years at the then current demand. It should be noted that the terrain around the Cook Inlet made a pipeline to transport gas to users in Canada or the Lower 48 states impracticable.

3.3 ECONOMIC DRIVER – MATCHING SUPPLY AND DEMAND

The US Securities and Exchange Commission ("SEC") places a strict requirement on the data used to report proven reserves by companies whose securities are traded on US exchanges. Rule 4-10(a) of Regulation S-X of the Securities Exchange Act of 1934 defines proved oil and gas reserves as follows:

"(a) ***Proved oil and gas reserves*** *are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date of the estimate is made. Prices include consideration of changes in existing prices provided by contractual arrangements, but not on escalations based upon future conditions.*

The determination of reasonable certainty is generated by supporting geological and engineering data. There must be data available which indicate that assumptions such as decline rates, recovery factors, reservoir limits, recovery mechanisms and volumetric estimates, gas-oil ratios or liquid yield are valid.

(b) Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of reservoir considered proved includes that portion delineated by drilling and defined gas-oil and/or oil-water contacts, if any, and the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limits of the reservoir.

(c)Reserves which can be produced economically through applications of improved recovery techniques (such as fluid injection) are included in the "proved" classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

(d) Estimates of proved reserves do not include the following:

- *Oil that may become available from known reservoirs but is classified separately as "indicated additional reserves";*
- *Crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors;*

- *Crude oil, natural gas, and natural gas liquids, that may occur in undrilled prospects;*
- *Crude oil, natural gas, and natural gas liquids, that may be recovered from oil shales, coal, gilsonite and other sources.*

The reserves excluded under (d) above are referred to as “probable reserves”. The definition of proven reserves is important because it places a constraint on the magnitude of the reserves that can be deemed proven in the early stages of the exploration and delineation of a field. Initially, proven reserves are likely to be significantly less than the recoverable reserves from a field. Over time, additional drilling and production activities will tend to increase the proven reserves by converting “probable reserves” to “proven”. In addition, the definition does not reflect advances in predictive techniques that have occurred over the past 71 years.

3.4 INFRASTRUCTURE

There are two principal components to the gas distribution system within the Cook Inlet that is owned by ENSTAR Natural Gas Company (“ENSTAR”) that supplies the residential and commercial users and the pipeline systems owned by the producers that provide gas to Agrium, Kenai LNG and the two electricity utilities – Chugach Electric (“Chugach”) and Anchorage Municipal Light and Power (“ML&P”).

The ENSTAR system receives gas from a number of gas producers, treats it and delivers it to power producers and light industry and domestic users. This system forms a horseshoe around the head of the Cook Inlet. The Unocal / Marathon Cook Inlet Gas Gathering System (“CIGGS”) connects the north side of the Cook Inlet to the south.

3.5 MAJOR USERS – CURRENT AND FUTURE

Current gas use in the Kenai Peninsula is approximately 200 billion standard cubic feet per year allocated as follows:

- Field and lease operations
- Power Generation
- Residential and commercial
- Kenai LNG
- Agrium

Natural gas is used in consumed in the production of oil, natural gas liquids and natural gas. It is used to generate power, drive compressors, provide heat, lift liquids from reservoirs and for purging lines. Some gas, primarily that associated with oil production (associated gas), is flared. There has been a dramatic reduction in natural gas consumption associated with field and lease operations, primarily as a result of reduced flaring. Lease consumption of natural gas has reduced from 57.5 billion cubic feet in 1971 to 15.2 billion cubic feet in 2001. The production profile presented in Figure 3.1-1 is net of this gas.

Residential and commercial demand for natural gas is linked to population size. Gas utility demand has increased from 10.2 billion cubic feet in 1971 to 34.9 billion cubic feet in 2001. Growth was approximately three percent per annum over the decade from 1991 to 2001. Similarly, installed power generation has increased to 928 MW (Chugach has 600 MW (450 MW peak load) and ML&P has 328 MW). Fuel gas demand in 2001 was 31.6 billion cubic feet, supplied primarily from the Beluga River field. ML&P has purchased a third stake in the Beluga River field from which it has obtained the bulk of its fuel gas since 1991. Initially, ML&P bought gas in equal shares from the three original partners in the field – Shell Oil, Phillips and Unocal under contracts that expire at the end of 2005. Shell offered its share of the field for sale in 1995. ML&P purchased this through bonds for US$120 million. The transaction was endorsed by the Assembly in October 1996. From January 2006, all of ML&P's gas will be provided from its share of the field's production. Moody's Investors Service recently estimated the cost of such gas to be US$1.85 per thousand cubic feet compared to US$3.85 per thousand feet had the expired contracts remained in place.

To monetize the large quantity of stranded gas available in the Cook Inlet, the early gas producers built two industrial facilities that continue in operation to this day. Unocal constructed an ammonia/urea facility that entered service in 1968 and Phillips and Marathon constructed a liquefied natural gas plant that entered service in 1969. These two facilities are located on adjacent plots at Nikiski on the Kenai Peninsula. In 1971 gas consumption was 26.8 billion cubic feet for power generation and utility use, 57 billion cubic feet for gas field operations, 19.5 billion cubic feet by the then Unocal-owned ammonia/urea plant and 63.2 billion cubic feet by the Kenai LNG plant. Thus total demand was 167 billion cubic feet. A second train was constructed at the ammonia/urea plant in 1978. This increased gas consumption from 19.5 billion cubic feet per day to 48.9 billion cubic feet. The LNG plant was debottlenecked in 1993 when the export license was renewed. Consumption of natural gas at the LNG facility increased from an average of 62.8 billion cubic feet per annum from 1971 through 1993 to 77.7 billion cubic feet per year from 1994 through 2001.

3.6 REGULATORY REGIME

The United States Federal Energy Regulatory Commission ("FERC") is the federal agency responsible for authorizing the site for onshore LNG baseload production plants and LNG import facilities. As such, FERC is the lead federal agency for the preparation of an Environmental Impact Statement ("EIS") in compliance with the requirements of the National Environmental Policy Act of 1969 ("NEPA"), the Council on Environmental Quality ("CEQ") regulations for implementing NEPA (40 Code of Federal Regulations ("CFR") 1500-1508), and FERC's regulations implementing NEPA (18 CFR 380). However, with respect to an expansion or change of use of the Kenai LNG Plant, the following federal, state and local agencies would probably have some form of involvement:

- United States Federal Energy Regulatory Commission ("FERC");
- United States Environmental Protection Agency ("EPA");
- United States Corp of Engineers ("CoE")
- U. S. National Oceanic and Atmospheric Administration ("NOAA")
- U. S. Fish and Wildlife Service ("USFWS")
- U. S. Natural Resources Conservation Service ("NRCS")
- U. S. Bureau of Indian Affairs ("BIA"), including separate contacts with the ?????? Nations of Native Americans
- U. S. Federal Emergency Management Agency ("FEMA")
- U. S. Coast Guard ("USCG")
- U. S. Federal Aviation Administration ("FAA")
- Alaska Department of Environmental Quality ("ADEQ")
- Alaska Department of Wildlife and Fisheries ("ADWF")
- Alaska Department of Natural Resources ("ADNR")
- Alaska State Land Office ("ASLO")

- Alaska Division of Historic Preservation ("ADHP")
- Alaska Department of Culture, Recreation and Tourism ("ADCRT")
- Alaska Department of Transportation and Development ("ADTD")
- Alaska Economic Development Department ("AEDD")

The National Gas Act ("NGA") Section 3 covers the application for a LNG receiving and regasification terminal, while the NGA Section 7(c) covers the application for the associated natural gas export pipeline.

In addition to the federal legislation noted above, FERC is also required to comply with Section 7 of the Endangered Species Act ("ESA"), the Magnuson-Stevens Fishery Conservation and Management Act ("MSA"), Section 106 of the National Historic Preservation Act ("NHPA"), and Section 307 of the Coastal Zone Management Act of 1972 ("CZMA").

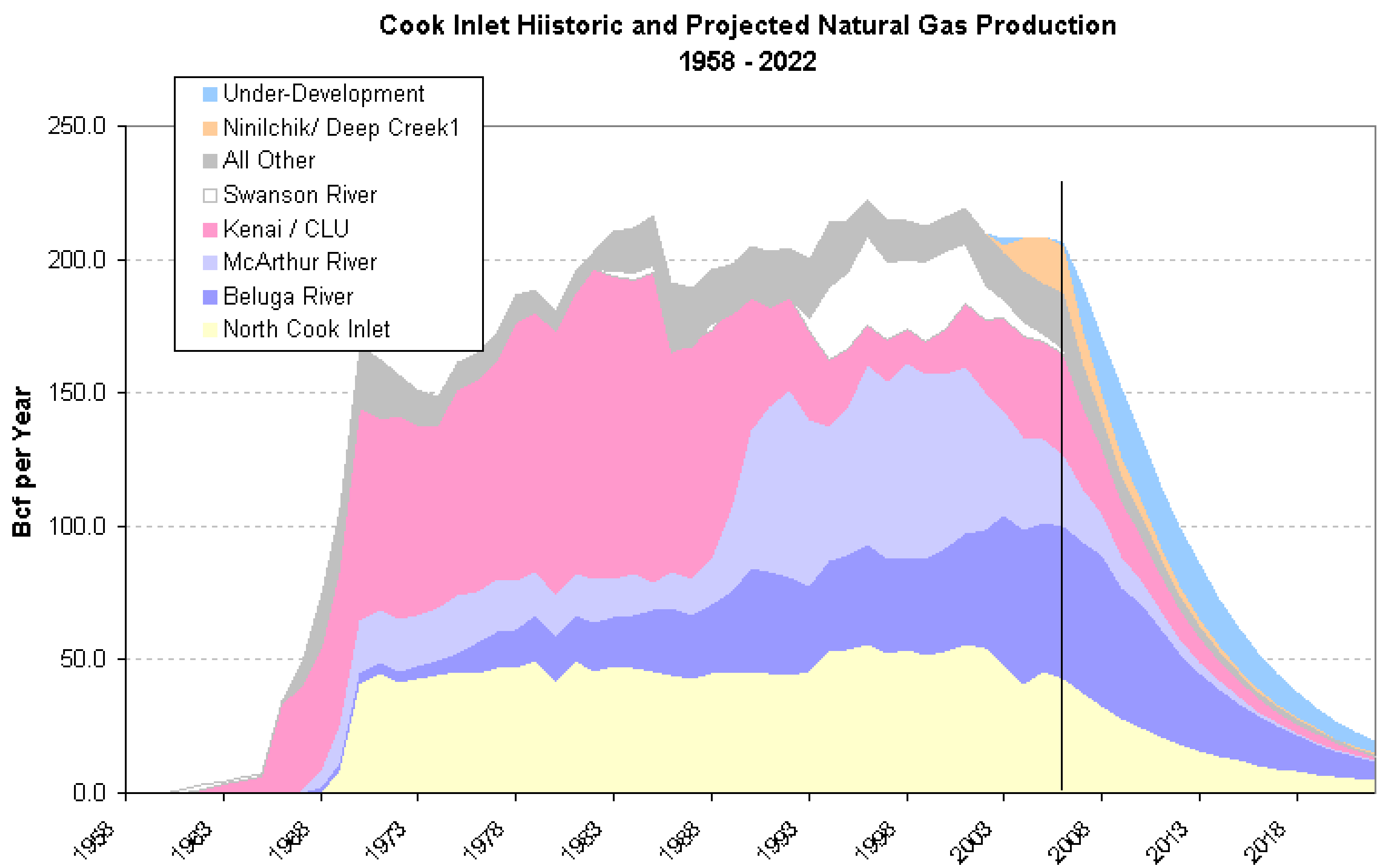
Requirements for an Environmental Impact Assessment ("EIA") are defined by the U. S. National Environmental Policy Act ("NEPA"). FERC will consult with several federal, state and local agencies during the public notice and comment period of the Environmental Impact Assessment that leads to the publication of the Environmental Impact Statement ("EIS"). Issues discussed during these meetings included the federal permitting process, shipping and safety issues, project dredge and fill requirements, and any wetland impacts and mitigation.

Air emissions will need to be addressed in the EIS. Threshold quantities of NO_x and CO are defined in the Federal Clean Air Act ("FCAA")

3.7 GAS PIPELINE SYSTEM

Continued use of the Kenai facility, without additional gas reserves within the Cook Inlet Basin, would require changing the direction of the flow of gas from that at present. This in turn would require an increase in the diameter of the pipeline serving parts of the current South-Central Alaska gas supply and distribution system. This can be achieved by replacing the existing system or augmenting sections with parallel lines, this is referred to as "looping". In addition, it would require regulation of the system to create a true grid in South-Central Alaska. Favorable resolution of Agrium's dispute with Unocal and Marathon over access rights to the Cook Inlet Gas Gathering System ("CIGGS") will effectively establish this. Historically, the Unocal and Marathon owned CIGGS has been reserved for the transportation of gas from their offshore fields. Independent oil and gas operators who have discovered modest gas reserves want to use CIGGS to transport their gas to Agrium's plant at Nikiski on the Kenai Peninsula.

Figure 3.1-1


Cook Inlet Hiistoric and Projected Natural Gas Production
1958 - 2022
Under-Development
Ninilchik/ Deep Creek1
All Other
Swanson River
Kenai / CLU
McArthur River
Beluga River
North Cook Inlet
250.0
200.0
150.0
100.0
50.0
0.0
Bcf per Year
1958
1963
1968
1973
1978
1983
1988
1993
1998
2003
2008
2013
2018

4.1 PREAMBLE

In 1967 Phillips Petroleum Company and Marathon Oil Company, as the Kenai LNG project developers and LNG exporters, executed a LNG sales agreement with LNG off-takers Tokyo Gas Company, Ltd. and Tokyo Electric Power Company, Inc. The original sales contract was for a term of 15 years with options to extend for an additional five years. This sales contract was the catalyst for the construction of the Kenai LNG Plant at Nikiski on the Kenai Peninsula. At the same time Unocal was building a nitrogen products plant to monetize its gas reserves. Unocal subsequently sold its ammonia/urea plant to the Canadian company, Agrium. The plants are constructed on adjacent plots.

The Kenai LNG plant has been in continuous service since 1969. The facility has been expanded twice to a present capacity of 1.57 million tonnes per year. Tables 4.1-1 through -3 demonstrate the improvement in production capacity over time. The plant was originally designed to liquefy 172.6 MMscfd of stranded natural gas produced from nearby Cook Inlet area gas production fields. The term “stranded gas” refers to the lack of a local market sufficiently large to justify the cost of gas exploration, drilling and production. This lack of a sufficient local market for significant reserves discovered in the Kenai field led to the decision to build the LNG liquefaction plant to liquefy and export natural gas and thereby monetize the reserves.

Table 4.1-1
Original Parameters 1969

	Plant Tailgate Capacity – 24-hour average	Each LNG Storage Tank	Polar Alaska
Billion Btus	**174**	**800**	**1,600**
MMscf	**173**	**800**	**1600**
API barrels	**49,000**	**225,000**	**450,000**
Million cubic meters of gas	**4.9**	**23**	**45**
Cubic meters of Liquid	**7,800**	**36,000**	**72,000**
Tonnes Equivalent	**3,300**	**15,000**	**30,000**

Table 4.1-2
Parameters Mid-1970s to 1993

	Plant Tailgate Capacity – 24-hour average	Each LNG Storage Tank	Polar Alaska
Billion Btus	**200**	**800**	**1,600**
MMscf	**200**	**800**	**1600**
API barrels	**57,000**	**225,000**	**450,000**
Million cubic meters of gas	**5.6**	**23**	**45**
Cubic meters of Liquid	**9,100**	**36,000**	**72,000**
Tonnes Equivalent	**3,800**	**15,000**	**30,000**

Table 4.1-3
Parameters 1994 Onwards

	Plant Tailgate Capacity – 24-hour average	Each LNG Storage Tank	Polar Alaska
Billion Btus	220	800	2,000
MMscf	220	800	2,000
API barrels	63,000	225,000	550,000
Million cubic meters of gas	6.2	23	55
Cubic meters of Liquid	9,900	36,000	88,000
Tonnes Equivalent	4,200	15,000	37,000

At the time, the Kenai LNG Project was the world's largest LNG project, and also up to that time, it was the largest project in the history of both Phillips and Marathon. Phillips (now ConocoPhillips) has a 70 percent ownership in the project and responsibility for operation of the plant. Marathon has the remaining 30 percent interest in the plant and is responsible for operation of the two LNG carriers that transport the LNG to Japan. The plant was the first commercial application of the Phillips Optimized Cascade LNG technology, which utilizes three separate refrigeration cycles, propane, ethylene, and methane loops, configured in series operation. Over the years the LNG plant has undergone several debottlenecking expansions that have increased its liquefaction capacity to the current level of 220 MMscfd. This equates to approximately 3.5 million cubic meters (1.55 million metric tonnes) per annum of LNG exports, allowing for 350 days per year of onstream time (95 percent onstream availability).

The two original LNG tankers, "Polar Alaska" and "Arctic Tokyo," each with a cargo capacity of 71,500 cubic meters, began LNG transport service in 1969, and remained in service until 1993. They are still in operation currently in alternate service as the "Methane Polar" and the "Methane Arctic." In July and December 1993 these original tankers were replaced with the 87,500 cubic meter "Polar Eagle" and the Arctic Sun." Like their predecessors, they were designed for rough weather and cold temperature service. For several months of the year the Cook Inlet is covered in broken ice. The LNG tankers have ice reinforcement to the hull, propeller, shafting, and gearing. Each round trip requires approximately 18 days, and each LNG tanker makes 20 round trips per year. Thus, the combined transport capacity of both 87,500 cubic meter tankers is just sufficient to deliver the 3.5 million cubic meters of LNG production from the Kenai plant.

In 1989 following the end of the original LNG sales contract and extension, a new contract was negotiated, which extended through 2004, with an extension through 2009, the current end of the sales agreement. On April 2, 1999, Phillips and Marathon were granted a renewal of their export license by the US Department of Energy, office of Fossil Fuels for the period from April 2004 to March 2009. In Testimony to Joint Committee on Natural Gas Pipelines, on November 8, 2001, Scott Jepsen, Manager, Cook Inlet Group, stated that for an extension beyond 2009, there must be adequate reserves for the extension and to provide for the state's needs.

The decline of the Cook Inlet natural gas production, coupled to considerations of the remaining useful life of the Kenai plant after 40 years of operation, may mean the end of LNG exports from Alaska.

4.2 THE PLANT

The Kenai LNG plant design uses an early version of the Phillips Optimized Cascade LNG Process, Appendix E depicts the process flow scheme and provides an overview of the plant. Photograph 4.2-1 provides a general view of the plant and a LNG carrier at the berth. The feedstock to the Kenai LNG plant is almost pure methane. Upon arrival at the plant it is contacted with amine to remove carbon dioxide. Normally heavy components, including ethane, propane, and butanes are withdrawn from the system as the natural gas is cooled and the calorific content of the LNG product is controlled by adjusting the amount of heavy components withdrawn from the system. This enables various feed gas compositions to be processed while maintaining strict control of the LNG specification. Once the NGL components have been removed, the feed gas is condensed into a liquid, which is then flashed at sequentially lower pressures to produce LNG product at near atmospheric pressure. In the case of Kenai, impurities such as carbon dioxide are removed and the remaining hydrocarbons are liquefied.

The Phillips Optimized Cascade Process liquefies natural gas using three refrigerants, namely propane, ethylene, and methane in a three-stage refrigeration process. In the Kenai plant the propane, ethylene and methane stages are all configured in closed loops, whereas in more recent applications of the technology, methane is commingled with the feed gas in an open loop which allows unwanted nitrogen and other volatile contaminants to be removed efficiently from the feed gas. The major advantage of this modification is the elimination of the fuel gas compressor. In the case of Kenai, this is a GE Frame 3 CGT-driven unit.

After chilling and finally condensing high pressure gas with propane, ethylene and methane refrigerants, the liquefied gas is then flashed (depressurized) to atmospheric pressure which further chills the gas to -257 °F (-161°C). Flashing generates vapor (gas) which is compressed and recycled. Heavier hydrocarbons are condensed prior to the formation of LNG and these heavier liquids are recycled to the upstream stabilizer tower.

In the Kenai LNG plant, each of the three integrated refrigeration systems utilizes two 50 percent compressors, operating in parallel service, with each individual compressor driven by a General Electric (“GE”) Frame 5 combustion gas turbine (“CGT”). ConocoPhillips refers to this as the “two-train-in-one’ reliability concept whereby a single train of liquefaction heat exchangers are served by two compressors operating in parallel on each refrigerant. The advantage of this configuration is that downtime, scheduled or unscheduled, of a compressor and/or CGT driver does not result in total loss of production from the train. Thus a CGT can be taken out of service for a hot pass inspection without shutting down the plant as a whole. Moreover, over half of the train capacity is available provided that at least one compressor is running in each refrigeration loop. Depending on which compressor is down, adjustments in operating parameters can still yield up to 80 percent of nameplate capacity. Conversely, the system can also be turned down to low levels of production. This is beneficial when production needs to be reduced, by way of example to prevent filling the LNG tanks to capacity when a LNG carrier is delayed. Liquefaction heat exchangers at Kenai have demonstrated turndowns to 10 percent of full capacity.

All the refrigeration exchangers are brazed aluminum plate fin heat exchangers. At the time the plant was designed, this was a novel application of patented Phillips technology. The technology originated in the aeronautical industry. While design and fabrication techniques have improved over the past 37 years, these units have performed extremely well. This type of heat exchanger is now used in a wide range of low temperature services.

Kenai was the first LNG Plant to use CGT to drive the compressors. Previous practice had been to use steam turbines. Recent practice in LNG plant design has been to balance power requirements of the three refrigerant loops so that identical drivers can be used for all three refrigerants while also using the full power. In this case, the CGTs do not operate at full power, i.e. against temperature limits. Moreover, each CGT receives an annual inspection as part of the annual two-week turnaround. This turnaround is concurrent with the annual inspection of the LNG carriers. It is our understanding that the CGTs are now world-class leading in terms of years of continuous service. The longevity of these units is a major consideration in determining the remaining useful life of the plant as whole. It should be noted that there is a reduction in the efficiency of a CGT over time. It is our understanding that in the case of Kenai LNG this degradation is still well within the bounds of economic acceptability.

LNG is stored in three single containment tanks. The single containment tank comprises a steel outer tank and an aluminum inner tank. Approximately three feet of insulation is provided between the inner and outer tanks. These tanks are small by modern day standards. Each tank has a capacity of 225,000 barrels (36,000 cubic meters). By comparison, the largest tanks currently constructed for baseload LNG plants have a capacity of 165,000 cubic meters. The tanks are also unusual by modern day standards in that LNG is supplied to and taken from the tank from inlets and outlets located near the base of the tank. Contemporary practice is to feed and extract LNG from the top of the tank to eliminate penetrations through the side wall. Should a significant leak occur, the LNG will be contained within a bunded area from where it will be routed to a burn pit. This method of containment is stipulated by the US Federal Energy Regulatory Commission (“FERC”).

LNG is pumped from the LNG tanks to dedicated LNG carriers that berth at a dedicated LNG Berth. The connection between the rundown lines and loading manifold on the LNG carrier is made through articulated, cryogenic loading arms. These loading arms accommodate a tidal range of 30 feet. The LNG carriers berth without the assistance of tugs. While this is unusual, it is understandable based on the width of the inlet at this point. It does provide a significant operational saving when compared to 40 tug-assist berthings per annum.

Power for the plant is provided by the local utility.

Photograph 4.2-1
Overview of the Kenai LNG Plant

5.1 PREAMBLE

Over the years the LNG plant has undergone several debottlenecking expansions that have increased its liquefaction capacity to the current level of 214 MMscfd. This equates to approximately 3.5 million cubic meters or 1.45 million metric tonnes per annum of LNG exports, based on 350 days per year of onstream time (95 percent onstream availability). The decline of the Cook Inlet natural gas reserves, coupled with the end of the useful life of the Kenai plant after 40 years of operation, could very likely mean the end of LNG exports from Alaska. However, if the proposed new ANGP pipeline is constructed to monetize the very large gas reserves in the North Slope area, and if a new Spur Line branch from the ANGP pipeline is constructed from either the Fairbanks or Delta Junction to the Cook Inlet area, a new LNG liquefaction plant could be constructed allowing LNG exports from Alaska to continue for many years to come.

Current consumption rate is approximately 548 MMscfd, which includes the natural gas consumed by the Agrium fertilizer plant and the Kenai LNG liquefaction plant. The future of continued operations at the Agrium facility is closely related to future natural gas price. Feedstock price must allow the plant to be competitive in the Asian markets. Shutdown of the Agrium facility could benefit the Kenai plant by reducing demand on the remaining reserves in the Cook Inlet Basin. An external supply of gas, such as that proposed from the North Slope via the ANGP and Spur Line, would most likely be beneficial to the continued operation of both the Kenai LNG Plant and the Agrium fertilizer plant. Previous studies regarding the Spur Line have indicated an initial capacity of 500 MMscfd, which approximates to the current Cook Inlet area daily average consumption rate. This would appear to be a reasonable supply rate to maintain the status quo. In effect, demand in excess of production capacity, would be met by North Slope supply. We note that the peak winter demand, when both of these plants are operating at capacity, is about 800 MMscfd.

5.2 GAS SUPPLY

Previous ANGDA studies regarding monetization of the stranded North Slope gas reserves have indicated that the most likely scenario for utilization of this gas would be to build the new ANGP gas transmission trunkline parallel to the TAPS line down through the Fairbanks and Delta Junctions. The new trunkline would then be routed southeastward across Canada, with termination at either the Wamsutter Hub in Wyoming or the Chicago Hub in Illinois. North Slope gas is currently being re-injected into the oil and gas production formations for reservoir pressure maintenance. The gas is lean in terms of hydrocarbon content, but it does have a relatively high carbon dioxide content, approximately 11.5 volume percent. Before the gas can be transported from the North Slope, the gas must be at least dehydrated, as wet gas with this level of carbon dioxide content would otherwise be quite corrosive to gas compression facilities and to the carbon steel transmission pipeline. Typically this type of gas dehydration is performed utilizing the simple and well-proven triethylene glycol ("TEG") dehydration process. However, typical natural gas pipeline specifications limit the content of various impurities, including hydrogen sulfide, nitrogen, carbon dioxide, water vapor, and the like. In addition, they specify maximum and minimum values for gross heating value. Most likely the basic gas treatment will be undertaken at the North Slope such that the resulting treated gas stream will then meet pipeline specifications in both Canada and the USA with respect to impurities. Approximate compositions for the untreated and treated gas streams are listed in Table 5.2-1. The untreated gas has a gross heating value of 952 Btu per scf primarily due to the dilution effect of the non-combustible carbon dioxide content. A simple absorption process should easily remove the hydrogen sulfide and provide bulk carbon dioxide removal. The resultant treated gas would contain 1.5 to 2.0 volume percent carbon dioxide or less, in compliance with most Canadian and U.S. interstate pipeline specification requirements. It would then have a higher heating value, slightly in excess of 1060 Btu per scf. The composition also indicates some heavier hydrocarbon content, heptanes and heavier, which may also have to be removed to meet hydrocarbon dewpoint specifications. Removal of these hydrocarbons would lower the heating value slightly. Carbon dioxide and hydrogen sulfide removed from the North Slope gas would likely be reinjected into the oil-bearing formations for reservoir pressure maintenance or utilized for enhanced tertiary oil recovery.

The new Spur Line into the Cook Inlet area would most likely commence at Delta Junction southeast of Fairbanks, assuming the Highway Pipeline is approved. Alternatively, if the ANGP is approved, the Spur Line would commence near Glennallen. In either case, the Spur Line would most likely terminate near Palmer, where it would connect into the ENSTAR Gas Company natural gas pipeline distribution system.

Table 5.2-1
Untreated and Treated North Slope Gas Streams

Component	Untreated North Slope Gas Volume Percent	Treated Gas From North Slope Volume Percent
Nitrogen	0.6202	0.6907
Carbon Dioxide	11.5533	1.5000
Methane	81.1162	90.3363
Ethane	5.0594	5.6345
Propane	1.4542	1.6195
Iso-Butane	0.0767	0.0854
N-Butane	0.0967	0.1077
Iso-Pentane	0.0084	0.0094
N-Pentane	0.0078	0.0087
Hexanes	0.0041	0.0046
Heptanes Plus	0.0030	0.0033
Hydrogen Sulfide, ppmv	10-20	<4.0
Benzene, ppmv	6-16	Trace
Octanes Plus, ppmv	12-15	Trace
Mercury, ppbw	1-2	1-2
Water Vapor, Pounds/Mscf	saturated	<4.0
Total	100.0000	100.0000
Molecular Weight	20.55	17.89
Gross Heating Value, btu/scf	952.05	1060.27

The new LNG liquefaction plant would likely obtain its feed gas supply from this system. However, Stone & Webster Consultants has not made a definitive evaluation of this system to verify that the Spur Line gas flow of 500 MMscfd can flow southwest to the existing Kenai plant site. A new pipeline loop might be required to handle the additional gas throughput. We would expect this to be constructed in the existing right-of-way.

5.3 RESIDUAL LIFE OF THE FACILITIES

As explained in Section 4.0, three integrated refrigeration systems are employed. In Kenai, each of the three systems comprises two 50 percent compressors, operating in parallel service, with each individual compressor driven by a General Electric ("GE") Frame 5 combustion gas turbine ("CGT"). ConocoPhillips refers to this as the "two-train-in-one' reliability concept whereby a single train of liquefaction heat exchangers are served by two compressors operating in parallel on each refrigerant. The advantage of this configuration is that downtime, scheduled or unscheduled, of a compressor and/or CGT driver does not result in total loss of production from the train. Thus a CGT can be taken out of service for a hot pass inspection without shutting down the plant as a whole. Moreover, over half of the train capacity is available provided that at least one compressor is running in each refrigeration loop. Depending on which compressor is down, adjustments in operating parameters can yield up to 80 percent of nameplate capacity. By the time the current Kenai LNG sales agreement expires in 2009, this plant will have been in continuous operation for 40 years. The longevity of these CGT units is a major consideration in determining the remaining useful life of the plant as whole.

Typically gas turbines are subject to a prescribed major maintenance schedule which includes a hot gas generator refurbishment every three years and a major power turbine overhaul every six years. In extra-clean service, these intervals can be extended to possibly four and eight years, respectively. Stone & Webster Consultants has not reviewed the maintenance records for the Kenai plant. However, we were advised by ConocoPhillips that the CGT undergo annual maintenance. Regular routine maintenance has most likely contributed to the longevity of these machines. The condition of the CGT would obviously influence the decision regarding continued operations for the Kenai plant at the conclusion of the current LNG sales agreement.

Another issue is the technology utilized in the design of these gas turbines. At the time these units were fabricated the heat rate, or the fuel gas consumption rate for GE Frame 5 turbines of that era was approximately 11,000 btu per horsepower-hour at optimum efficiency. The Kenai units operate at greatly reduced capacity so the actual heat rates are likely to be 12,500 btu/hp-hr or higher. Newer gas tubines based on the latest combustion technology are substantially more efficient. For example, the mechanical drive LM-2500 gas turbine units considered by Stone & Webster Consultants for the new expansion (see Section 6.0) have a heat rate of 6,750 btu/hp-hr, which greatly reduces overall operating costs.

5.4 EQUIPMENT REPLACEMENT

Section 6.0 discusses expansion of the Kenai LNG Plant. This assumes that an ample supply of gas is available for an expansion of the plant to essentially double its current liquefaction capacity.

5.5 REGULATORY REQUIREMENTS

An extension of the operating life of the plant would require an extension of the operating license and the export permit.

5.6 ECONOMIC ASSESSMENT

In this instance, Stone & Webster Consultants has assumed like-for-like replacement costs of US$300 million. The annual LNG export volume of 1.50 million metric tonnes equates to approximately 76,335,000 Mscf per year. The annual fixed and variable operations and maintenance costs for the new facility are estimated at approximately US$60 million per annum. Assuming a simple payout period of three years, the annual return on equity would be US$100 million per annum (300/3). Thus the gross margin from LNG exports must be US$160 million per annum to satisfy the three-year simple payout criteria. This equates to a base plant LNG sales price component of approximately US$2.10 (160,000,000/76,335,000). Alternately, this same gross margin figure could be considered as a tolling fee, assuming the North Slope operators retained ownership of the natural gas and the resultant LNG. The North Slope operators would then pay the liquefaction plant owners this same tolling fee for liquefaction and LNG tanker loading services. The North Slope owners would also be obligated to pay all other associated fees in bringing the gas to market on the U.S. west coast.

Adding LNG shipping costs to the U.S. west coast of approximately US$0.50 per Mscf plus another US$0.50 per Mscf for ANGP and Spur Line pipeline tolls would result in a total price uplift of US$3.10 over the base purchase price of the delivered natural gas. Assuming the netback gas price is equivalent to the current Cook Inlet price of US$2.50/Mscf, the delivered price of the LNG to the west coast receiving terminal would be approximately US$5.60 per Mscf. Adding a downstream receiving and regasification terminal and pipeline toll fee of an additional US$0.50 per Mscf would still result in a delivered west coast natural gas sales price of US$6.10 per Mscf. This value compares to a current Henry Hub (Louisiana) price of US$6.30 per Mscf and an average over the past year of approximately US$10 per Mscf and a winter 2006 forecast price of US$11 per Mscf. Therefore, based on current gas prices, there is scope to recoup that proportion of the pipeline investment and operating costs associated with delivery of North Slope gas to the South-Central Alaska in general and an upgraded Kenai LNG liquefaction plant in particular.

5.7 CONCLUSIONS

Provided that an adequate supply of gas can be substantiated, continued operation of the Kenai LNG plant is economically viable.

6.1 PREAMBLE

The Kenai LNG liquefaction plant is currently supplied with natural gas feed from reserves in the Cook Inlet area oil and gas production fields. According to the South-Central Alaska Natural Gas Study[1], The original recoverable gas reserves from the Cook Inlet area were estimated at approximately 8.4 trillion standard cubic feet ("tscf"), and the remaining proven reserves as of January 1, 2006 were 1.6 tscf.

The current capacity of the Kenai liquefaction plant (214 MMscfd) and the Agrium ammonia and urea fertilizer plant (142 MMscfd), together with the annual average residential and commercial consumption (192 MMscfd) totals 548 MMscfd. According to the aforementioned study, Agrium requires natural gas at a price of approximately US$2.00/MMbtu to be competitive in the Asian fertilizer markets. Assuming the Agrium plant is shut down in late 2006 or thereafter due to the lack of feed gas at an economically viable price, and assuming the Kenai LNG plant is shut down coinciding with termination of its LNG export contract in 2009, the pre-existing gas reserves are only able to sustain the current residential and light commercial demand through 2012/2013. By 2025, this demand is expected to have increased from 192 MMscfd to approximately 300 MMscfd.

Over the years the LNG plant has undergone several debottlenecking expansions that have increased its liquefaction capacity to the current level of 214 MMscfd. This equates to approximately 3.5 million cubic meters or 1.45 million metric tonnes per annum of LNG exports, based on 350 days per year of onstream time (95 percent onstream availability). The decline of the Cook Inlet natural gas reserves, coupled with the end of the useful life of the Frame 5 combustion gas turbine ("CGT") compressor drivers after 40 years of operation, could mean the end of LNG exports from Alaska. However, if the proposed new ANGP and associated Spur Line pipelines are constructed to monetize the substantial gas reserves in the North Slope area, then a new LNG liquefaction plant could be constructed at Kenai allowing a continuation of LNG exports from Alaska. The Cook Inlet Basin can sustain gas production through to 2025 albeit at a much reduced rate. While previous studies indicated an initial capacity of 500 MMscfd for the Spur Line, a higher capacity would be required to accommodate peak winter demand, growth in domestic demand and the feedrate to an expanded plant. Our assumption is that the Spur Line will need to have a capacity of one billion cubic feet per annum to support an expanded Kenai LNG plant, continued operation of the Agrium fertilizer plant and domestic and residential growth.

Stone & Webster Consultants has assumed that the maximum economically viable capacity of a new LNG liquefaction plant is approximately 3.0 million metric tonnes per annum. The assumed new LNG liquefaction plant would require about 455 MMscfd of feed gas to produce 7.2 million cubic meters per annum of LNG exports. This is essentially double the size of the existing liquefaction plant. Our assumption is that a doubling of plant capacity will also require doubling the existing storage and shipping capacities.

6.2 NATURAL GAS PIPELINE CONNECTION

Previous ANGDA studies regarding monetization of the stranded North Slope gas reserves have indicated that the most likely scenario for utilization of this gas would be to build the new ANGP gas transmission trunkline parallel to the TAPS line down to the Fairbanks and Delta Junctions. The new trunkline would then be routed southeastward across Canada, with termination at either the Wamsutter Hub in Wyoming or the Chicago Hub in Illinois. North Slope gas is currently being re-injected into the oil and gas production formations for reservoir pressure maintenance. The gas is lean in terms of hydrocarbon content, but it does have a relatively high carbon dioxide content, approximately 11.5 volume percent. As a minimum, before the gas can be transported from the North Slope, it must be dehydrated. Wet gas with this level of carbon dioxide content would otherwise be corrosive to gas compression facilities and to the carbon steel transmission pipeline. Typically, this type of gas dehydration is performed utilizing contact with glycol. A suitable process is the simple and well-proven triethylene glycol (“TEG”) dehydration. Natural gas pipeline specifications limit the content of various impurities, including hydrogen sulfide, nitrogen, carbon dioxide, water vapor, and heavy hydrocarbons and specify maximum and minimum limits for gross heating value. Most likely the basic gas treatment will be undertaken at the North Slope such that the resulting treated gas stream will then meet pipeline specifications in both Canada and the USA with respect to impurities. Approximate compositions for the untreated and treated gas streams are listed in Table 6.2-1. Untreated gas has a gross heating value of 952 Btu per scf primarily due to the dilution effect of the non-combustible carbon dioxide content. A simple absorption process can be used to remove the hydrogen sulfide and carbon dioxide. The resultant treated gas will contain 1.5 to 2.0 volume percent carbon dioxide or less, in compliance with most Canadian and U.S. interstate pipeline specification requirements. Treated gas would then have a higher heating value slightly in excess of 1060 Btu per scf. In addition, the heavier hydrocarbon content, heptanes and heavier, will most likely need to be removed to meet hydrocarbon dewpoint specifications. Removal of the heavier hydrocarbons would lower the heating value slightly. Both the carbon dioxide and hydrogen sulfide removed from the North Slope gas would likely be reinjected into the oil-bearing formations for reservoir pressure maintenance or utilized for enhanced tertiary oil recovery.

Table 6.2-1
Untreated and Treated North Slope Gas Streams

Component	**Untreated North Slope Gas Volume Percent**	**Treated North Slope Gas Volume Percent**
Nitrogen	0.6202	0.6907
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Propane	1.4542	1.6195
Iso-Butane	0.0767	0.0854
N-Butane	0.0967	0.1077
Iso-Pentane	0.0084	0.0094
N-Pentane	0.0078	0.0087
Hexanes	0.0041	0.0046
Heptanes Plus	0.0030	0.0033
Hydrogen Sulfide, ppmv	10-20	<4.0
Benzene, ppmv	6-16	Trace
Octanes Plus, ppmv	12-15	Trace
Mercury, ppbw	1-2	1-2
Water Vapor, Pounds/Mscf	saturated	<4.0
Total	100.0000	100.0000
Molecular Weight	20.55	17.89
Gross Heating Value, btu/scf	952.05	1060.27

The new Spur Line into the Cook Inlet area would likely commence at Delta Junction southeast of Fairbanks, assuming the Highway Pipeline Project is approved. Alternatively, if the ANGP is approved, the Spur Line would commence near Glennallen. In either case, the Spur Line would terminate near Palmer, where it would connect into the ENSTAR Gas Company natural gas pipeline distribution system. The new LNG liquefaction plant would likely obtain its feed gas supply from this system. While Stone &

Webster Consultants has not made a definitive evaluation of the ENSTAR system, looping would be required to accommodate flow of up to 1000 MMscfd under peak winter load.

6.3 NEW TRAIN CONFIGURATION

Stone & Webster Consultants has visited the existing Kenai LNG facility, and confirms that it has been well maintained over the years, and it would appear that a substantial portion of the facilities could be re-used in support of a new and larger liquefaction facility. However, the basic feed gas pre-treatment facilities and the basic liquefaction process equipment will likely be replaced due to age and size limitations. The existing General Electric ("GE") Frame 5 CGT refrigeration compressor drivers utilize old, less efficient gas turbine technology than is now available. After forty years of continuous operation they will be nearing the end of their useful service life. Most of the utility and support systems, however, would likely remain in service in the new operation following modernization and expansion as required. Our assumption is that the existing LNG storage tanks and the marine loading facilities will continue in service. We note that the water depth at the LNG berth is 43 feet at low tide. A 130,000 cubic meter capacity LNG carrier has berthed at the marine loading facilities.

As shown in Section 6.2, the treated North Slope feed gas stream will contain less than 2.0 volume percent of carbon dioxide following bulk carbon dioxide removal. However, the remaining carbon dioxide must be removed prior to liquefaction. ConocoPhillips utilizes a 50 percent aqueous solution of di-glycolamine ("DGA"), a primary amine, as the amine absorbent at the Atlantic LNG Plant in Trinidad and Tobago. Primary amines exhibit the highest efficiency among amines for carbon dioxide removal, and DGA is particularly well-suited to the Cook Inlet area climate, as this solution has a minus 40°F freezing point. Therefore, the use of DGA will require less-stringent winterization protection than other absorbents.

A higher feed gas flow of up to 500 MMscfd, coupled with the higher carbon dioxide content, will require complete replacement of the feed gas pretreatment facilities. Note, the LNG plant is able to process more gas when temperatures are low. We would expect the seasonality effect to be of the order of 10 percent. The flow sheet for the expansion will remain essentially the same as before. Gas will first enter a new inlet separator to remove pipe mill scale and other particulates as well as any liquid droplets. North Slope gas has a higher content of heavier hydrocarbons than Cook Inlet gas, which is almost pure methane. However, hydrocarbon dewpoint control will have been implemented during the initial pre-treatment of the gas at the North Slope, so liquid accumulation should be minimal. Therefore, no special liquids handling facilities should be required at the plant.

The inlet feed gas will enter the facility at a temperature that is too low to allow amine processing. Therefore, the inlet gas must be pre-heated in a gas-to-gas exchanger against treated gas from the downstream amine absorption tower. Such use of process heat and process cold is an intrinsic part of economic plant design. Further heating of the gas will likely be accomplished in an exchanger against warm amine solution and/or against glycol/water solution that has been heated by waste heat recovery from gas turbine exhaust. Warm gas will then flow upward through the absorption tower against amine solution flowing downward. Lean gas from the top of the absorber will then flow through the gas-to-gas exchanger which cools it and condenses some water vapor contained in the gas. Condensed water will be removed in a scrubber vessel, and returned to the rich amine flash drum.

The rich amine solution leaving the bottom of the absorber tower will contain the absorbed carbon dioxide, which will be routed to the new amine regeneration facilities comprising an amine stripping tower and auxiliaries. Regeneration entails boiling and extracting the absorbed carbon dioxide from the amine solution. Heat input from a regenerator reboiler and a DGA solution reclaimer provide the required heat input for solution regeneration. Recovered carbon dioxide gas from the regeneration system is typically vented to the atmosphere. However, it could be compressed and delivered to the adjacent Agrium plant as feedstock for urea production, assuming the Agrium plant continued to operate. Lean amine solution from the regeneration system will be returned to the top of the absorber to complete the loop.

Treated feed gas will then be routed to a new and larger molecular sieve dehydration unit. This unit would typically consist of a conventional cyclical design similar in concept to the existing unit. Dry gas leaving this unit would contain less than 0.1 ppmv of water vapor. Dehydrated gas would then flow through a carbon filter impregnated with chemicals that react with and remove any contained elemental mercury. Mercury is removed to present degradation of the brazed aluminum plate-fin heat exchangers ("PFHE"). The impregnated activated carbon is sacrificial, i.e., it is disposed of rather than regenerated once it has been spent, which duplicates the existing operation. One last particulate filter then removes molecular sieve and carbon particles from the treated gas to complete the pre-treatment processing.

Following pre-treatment, the feed gas enters the Optimized Cascade liquefaction section. Stone & Webster Consultants anticipates that the new liquefaction facility will have essentially double the capacity of the existing facility, and will incorporate several design enhancements that have been developed over the past 35 years. For example, the existing plant utilizes a closed methane refrigeration loop. The newer design would utilize an open loop, whereby storage tank vapor from boil-off, tanker loading, and from LNG flashing are returned to the methane refrigeration condenser and recovered as LNG. In the existing Kenai plant these vapors are compressed and sent to the plant fuel gas system, thereby losing the refrigeration "cold" contained in these streams. The new liquefaction system would also incorporate a contemporary instrumentation and control system.

The primary revision to the liquefaction system will be the utilization of new, modern gas turbine drivers that will provide the shaft horsepower required by the new and larger refrigerant compressors. While Frame 5 drivers are still used extensively as drivers, Stone & Webster Consultants anticipates that an aero derivative may be selected for this application, specifically the GE LM-2500-DLE gas turbine, where "DLE" refers to Dry Low Emissions. Combustors on this turbine are specifically designed to produce lower emissions nitrogen oxides ("NOx") and other air emissions. Aero derivative gas turbines are well-suited for the two-in-one train design philosophy practiced by the Optimized Cascade technology. Major overhauls of aero derivatives are simpler than those on industrial turbines, albeit that a number of innovations have simplified the latter. In the case of the aero derivative turbine, the entire engine can be quickly replaced. It is then sent to a specialist workshop for overhaul. Conversely, the existing GE Frame 5 industrial turbines require on-site major overhauls. The use of aero derivatives should reduce major maintenance cost and improve onstream efficiency. Stone & Webster Consultants notes that aeroderivatives have been used in ConocoPhillips Darwin LNG plant in Darwin, Australia.

For a LNG liquefaction capacity of 3.0 million metric tones per annum, each LM-2500 gas turbine mechanical driver produces approximately 24,300 brake horsepower ("bhp"). Therefore six of these turbines produce 145,800 horsepower. By comparison, the existing GE Frame 5 gas turbines are capable of producing up to perhaps 38,000 horsepower each, which is substantially more than required by any of the existing refrigerant compressors. Therefore the existing turbines are operating in an inefficient manner. New LM-2500 gas turbines will require approximately 23 MMscfd of natural gas for fuel. This new LNG liquefaction plant configuration will also require approximately 16.5 MW of purchased electric power.

An alternate configuration could be the use of electric motors to drive the refrigerant compressors. Again, the Optimized cascade technology is particularly well-suited to this approach due to the use of multiple smaller drivers. Stone & Webster Consultants is aware that this option has been considered in previous LNG liquefaction plant case studies, but this option has yet to be put into practice. The largest two-pole synchronous motor built to date is about 71,000 horsepower but the technology is analogous to generators that have been manufactured at larger sizes. Therefore, the technology certainly exists to support this alternative for the new Kenai LNG plant. A two-pole motor, with electric power supplied at 60 Hertz, operates at a speed of 3,600 RPM. Comparatively a four-pole motor operates at a speed of 1,800 RPM. Depending on the availability of affordable electric power, this might be a viable option. This option also reduces air emissions from the plant, greatly simplifying environmental permitting. However, the power would be derived from a new gas-fired power station, a coal-fired plant, or hydroelectric power plant. Thus the net environmental benefit would need to be evaluated. Such an evaluation may form part of a wider energy optimization study for South-Central Alaska.

The new liquefaction system would again utilize two parallel turbine-driven refrigerant compressors for each of the three refrigeration loops. Brazed aluminum PFHE again would be the liquefaction exchangers of choice. Whereas the Cook Inlet feed gas contains virtually no heavier hydrocarbons, the North Slope gas does. Therefore, in the new exchanger design, inlet feed gas, chilled and partially condensed by the ethylene refrigeration condenser will be removed and passed through a vapor/liquid separator to remove the condensed heavier hydrocarbons. The remaining feed gas vapor will be returned to the ethylene condenser to complete the liquefaction process. This withdrawal prevents freezing of these heavier components in the liquefaction section at low temperatures. Stone & Webster Consultants assumes that the recovered liquids will be minimal in quantity and most likely will be sent to the plant fuel system.

As stated in Section 2, the existing Kenai LNG plant utilizes two 87,500 cubic meter LNG carriers, the “Polar Eagle” and the Arctic Sun.” Each round trip requires approximately 18 days, and each LNG tanker makes 20 round trips per year. Thus, the combined transport capacity of both 87,500 cubic meter tankers is sufficient to deliver the 3.5 million cubic meters of LNG production from the Kenai plant. This new liquefaction plant will export approximately 7.2 million cubic meters of LNG, or slightly more than double the current exports. Public domain documentation indicates that each of these LNG carriers requires approximately eighteen hours for loading, and a similar duration is assumed to be required for unloading. This rate is substantially lower than the 10,000 to 12,000 cubic meters per hour of most contemporary baseload LNG liquefaction plants. Since there are approximately nine days between each current shipment, ample time is available to add additional shipments to accommodate the higher export capacity. Therefore, Stone & Webster Consultants assumes that the existing LNG marine loading facilities will be adequate for the expanded facilities. Additional LNG carriers will most likely be required. While it is conceivable that these could be leased rather than purchased, the existing vessels are purpose-built because of the broken-ice that is encountered during winter. Accordingly, we assume that at least one additional vessel will need to be constructed.

Each existing Kenai LNG storage tank has a capacity of 36,000 cubic meters, resulting in a total plant capacity of 108,000 cubic meters. This is equivalent to almost eleven days of storage at a daily production rate of capacity of approximately 10,000 cubic meters per day. We would expect the existing LNG storage capacity needs to be increased. For the purpose of this exercise, we have not attempted to model the tankage/shipping cycle since the customer is not certain. We have assumed the installation of a new, full-containment 160,000 cubic meter storage tank, complete with three in-tank transfer/loading pumps, boil-off compressor, and associated auxiliaries. This larger size tank is typical of those currently being installed at most new LNG baseload plants and at new receiving and re-vaporization terminals on the U.S. Gulf Coast and elsewhere. Also this size will be sufficient to load the newer, larger LNG carriers of 140,000 cubic meters and larger.

6.4 PROJECT EXECUTION

An expansion of the type described above would probably require some five years to fully implement. In Stone & Webster Consultants' experience, permitting may control the overall duration of the Project. Conceptual design and the front end engineering design ("FEED") preparation, including a definitive cost estimate, would require approximately one year. Detailed engineering, procurement and construction would probably take an additional three years. Commissioning of utilities would commence while construction was nearing completion and continue for about six months after completion. However, the critical path for this overall schedule is construction of any additional LNG storage tanks, which require a minimum three-year completion schedule. In this case, with the availability of the pre-existing storage facilities, the overall schedule could likely be accelerated by at least one year and perhaps even two years, depending on the availability of a suitable pre-existing FEED package, etc.

6.5 ESTIMATED CAPITAL COST

As stated above, new pre-treatment and liquefaction systems will be required, as well as a new 160,000 cubic meter, full-containment LNG storage tank. Much of the existing support facilities and infrastructure, including the marine loading terminal, existing LNG storage tanks, and most of the buildings and utility systems will be used, with some expansion of utility and support facilities. This capital cost estimate incorporates a geographic cost adjustment factor for the Anchorage area of 1.4 times the equivalent U.S. Gulf Coast cost. Stone & Webster Consultants estimates the required capital cost as shown below in Table 6.5-1:

Table 6.5-1
New Kenai LNG Plant Capital Cost

Expenditure Description	**Million US Dollars**
New Pre-treatment and Liquefaction Process Facility Costs	1000
Additional and Expanded Utilities and Support Facilities	100
New 160,000 cubic meter Full-Containment LNG Storage Tank and Auxiliaries	100
Subtotal EPC Contract(s) Costs	**1200**
Owners' Cost at 25 Percent of EPC Contract Cost	300
TOTAL PROJECT CAPITAL COST	**1500**

6.6 REGULATORY IMPLICATIONS

Requirements for an Environmental Impact Assessment ("EIA") are defined by the U. S. National Environmental Policy Act ("NEPA"). FERC will consult with several federal, state and local agencies during the public notice and comment period of the Environmental Impact Assessment that leads to the publication of the Environmental Impact Statement ("EIS"). Issues discussed during these meetings include the federal permitting process, shipping and safety issues, project dredge and fill requirements, and any wetland impacts and mitigation.

Air emissions will need to be addressed in the EIS. Threshold quantities of NO_x and CO are defined in the Federal Clean Air Act ("FCAA").

6.7 ECONOMIC ASSESSMENT

The annual LNG export volume of 3.0 million metric tonnes equates to approximately 158,670,000 Mscf per year. The annual fixed and variable operations and maintenance costs for the new facility are estimated at approximately US$120 million per annum, or eight percent of the total installed capital cost. Assuming a simple payout period of three years, the annual return on equity would be US$500 Million per annum (1500/3). Thus the gross margin from LNG exports must be US$620 Million per annum to satisfy the three-year simple payout criteria. This equates to a base plant LNG sales price component of approximately US$3.91 (620,000,000/158,670,000). Alternately, this same gross margin figure could be considered as a tolling fee, assuming the North Slope operators retained ownership of the natural gas and the resultant LNG. The North Slope operators would then pay the liquefaction plant owners this same tolling fee for liquefaction and LNG tanker loading services. The North Slope owners would also be obligated to pay all other associated fees in bringing the gas to market on the U.S. west coast.

Adding LNG shipping costs to the U.S. west coast of approximately US$0.50 per Mscf plus another US$0.50 per Mscf for ANGP and Spur Line pipeline tolls would result in a total price uplift of US$4.91 over the base purchase price of the delivered natural gas. Assuming the netback gas price is equivalent to the current Cook Inlet price of US$2.50/Mscf, the delivered price of the LNG to the west coast receiving terminal would be approximately US$7.41 per Mscf. Adding a downstream receiving and regasification terminal and pipeline toll fee of an additional US$0.50 per Mscf would still result in a delivered west coast natural gas sales price of US$7.91 per Mscf. This value compares to a current Henry Hub (Louisiana) price of US$6.30 per Mscf and an average over the past year of approximately US$10 per Mscf. Therefore, based on current gas prices, there is scope to recoup that proportion of the pipeline investment and operating costs associated with delivery of North Slope gas to the South-Central Alaska in general and an expanded Kenai LNG liquefaction plant in particular.

A more conventional economic analysis of the proposed expansion would consist of calculation of the proposed cash flow pro forma, including depreciation and U.S. federal income taxes. Two cases have been evaluated, based on gross revenue required for a three-year simple payout and for a five-year simple payout. These calculations are presented in Table 6.7-1. As shown, the actual after tax project payout period for is 4.1 years, assuming that the EBITDA figure corresponds to a simple three-year payout gross income of US$500 Million per annum. This equates to a Book Value Rate of Return of 24.5 percent, which is a good return on equity and consistent with the return that we assume ConocoPhillips and Marathon would like to obtain. The second case results in an actual payout period of 6.3 years and a Book Value Rate of Return of 15.8 percent for revenues equivalent to a five-year simple payout period. This latter case is likely to be closer to the minimum economic performance that the Kenai plant owners will deem to be acceptable.. These cash flow pro formas are based on applying a ten-year straight line depreciation schedule to a depreciable investment of US$1200 Million, i.e., assuming only the EPC Contract portion of the total investment is considered as depreciable for federal taxation purposes.

Stone & Webster Consultants has also calculated the west coast delivered sales price based on using longer simple payout periods for comparative purposes. These calculations are also based on an annual plant operating cost ("OPEX") cost of US$120 Million and additive costs and fees of an additional US$4.00 per Mscf. The results are presented in Table 6.7-2. A three-year simple payout revenue results in a west coast delivered price of US$7.91 per Mscf as developed above. The five-year simple payout revenues result in a west coast delivered price of US$6.65 per Mscf.

As an entity of the State of Alaska, ANGDA can utilize tax-free bonds to finance the Project, making even longer equivalent payout periods economically viable. Accordingly, the delivered price corresponding to a ten-year simple payout at US$5.70 per Mscf, or perhaps even for a fifteen-year payout at US$5.39 per Mscf might still be economically viable.

Table 6.7-1
New LNG Liquefaction Plant Cash Flow Pro Forma
US$Million/Year

Cash Flow Inputs and Calculations	**3-Year Simple Payout**	**5-Year Simple Payout**
Facility Total Capital Cost	**1500**	**1500**
Return on Equity @ $1500/ payout period	500.0	300.0
Add Feed Gas Purchase Price @$2.50/Mscf	396.7	396.7
Add Shipping, Tolls, and Regas Fees @ $1.50/Mscf	238.0	238.0
Add Fixed and Variable Opex @ 8% of Total Capex	120.0	120.0
Gross Revenue Build-up	1254.7	1054.7
Subtract Feed Gas Purchase Cost	(396.7)	(396.7)
Subtract External Fees	(238.0)	(238.0)
Subtract Plant Operating Costs	(120.0)	(120.0)
Gross Income, EBITDA	500.0	300.0
Subtract Depreciation, $1200 MM inv, 10 yr straight line	(120.0)	(120.0)
Taxable Income	380.0	180.0
Federal Income Taxes at 35%	(133.0)	(63.0)
Net Income After Tax	247.0	117.0
Add Depreciation For Actual Cash Flow	120.0	120.0
Actual Annual Net Income on Cash Flow Basis	**367.0**	**237.0**
Actual Project Payout on Cash Flow Basis	**4.1 Years**	**6.3 Years**
Book Value Rate of Return	**24.5 Percent**	**15.8 Percent**

Table 6.7-2
West Coast Delivered Gas Price
For Alternate Simple Payout Periods

Simple Payout Period Years	Return on Equity Plus Plant Opex Cost US$/Mscf	Purchase Price Plus Shipping, Pipeline, and Regas Fees, US$/Mscf	Delivered West Coast Natural Gas Price US$/Mscf
3	3.91	4.00	7.91
4	3.12	4.00	7.12
5	2.65	4.00	6.65
10	1.70	4.00	5.70
15	1.39	4.00	5.39
20	1.23	4.00	5.23
25	1.13	4.00	5.13

6.8 CONCLUSIONS

Expanding the annual capacity of the Kenai LNG plant to an assumed maximum economic size of 3.0 million metric tonnes per annum will require new pre-treatment and liquefaction systems. In addition, we have assumed the need for a new 160,000 cubic meter, full-containment LNG storage tank. Conversely, we have assumed that much of the existing support facilities and infrastructure, including the marine loading terminal, existing LNG storage tanks, and most of the buildings and utility systems will continue in use, with some expansion of utility and support facilities. Stone & Webster Consultants estimates the capital cost of the expansion at US$1200 million for the EPC Contract(s) plus US$300 million in separate Owners' Cost, for a total capital investment of US$1500 million. This estimate incorporates a geographic cost adjustment factor for the Anchorage area of 1.4 times the equivalent U.S. Gulf Coast cost.

Assuming a simple payout period of three years, the annual gross income or return on equity would be US$500 million per annum (1500/3). The annual fixed and variable operating costs for the new facility are estimated at approximately US$120 million per annum, or eight percent of the total installed capital cost. Thus the gross margin from LNG exports must be US$620 million per annum, to satisfy the three-year simple payout criteria. This equates to a liquefaction plant LNG sales price component of approximately US$3.91 per Mscf. Comparatively, the five-year simple payout revenues result in a base LNG price of US$2.65 per Mscf. Adding in a current gas purchase price of US$2.50 per Mscf, plus combined pipeline tolls, shipping costs to the U.S. west coast, and terminal fees for receiving, regasification, and pipeline export of US$1.50 per Mscf results in west coast delivered gas prices of US$7.91 and US$6.65 per Mscf, respectively for the three-year and five-year simple payout cases. These values compare with the current Henry Hub (Louisiana) price of approximately US$6.30 per Mscf and an average price over the past 12 months of about US$10 per Mscf. Therefore, there is scope to deliver North Slope gas to the new Kenai liquefaction facilities, and ultimately into the U.S. west coast market.

A more conventional economic analysis of the proposed expansion would consist of calculation of the projected cash flow pro forma, including depreciation and U.S. federal income taxes. Two cases have been evaluated, based on gross revenue required for a three-year simple payout and for a five-year simple payout. After-tax payout period for the three-year case is 4.1 years, which equates a Book Value Rate of Return of 24.5 percent, which is a good return on equity. The five-year case results in an actual after-tax payout period of 6.3 years and a Book Value Rate of Return of 15.8 percent. This latter case is likely to be closer to the projected economic performance considered to be acceptable to the Kenai plant owners, assuming the owners will provide all equity contributions and financing. However, as an entity of the State of Alaska, ANGDA can utilize tax-free bonds to finance the Project, making even longer equivalent payout periods economically viable.

7.1 PREAMBLE

The basic purpose of a peak shaving plant is to condense pipeline natural gas to produce liquefied natural gas (LNG) and accumulate this LNG in large cryogenic storage tanks during months of low demand, when natural gas production exceeds consumption. During periods of peak demand when demand exceeds production, the stored LNG is pumped from the storage tanks, vaporized back to natural gas, and injected into the distribution system to meet these peak natural gas demands.

Fundamentally, a peak shaving plant is virtually identical in terms of a flow sheet to a base load liquefaction plant, albeit normally with a much smaller throughput capacity. In both a baseload LNG liquefaction plant and a peak shaver plant, inlet natural gas pretreatment facilities remove impurities such as water vapor, carbon dioxide, and heavier hydrocarbon compounds from the natural gas feedstock. If not removed, these impurities would freeze and accumulate like frost inside the downstream liquefaction equipment, which operate at extremely cold (cryogenic) temperatures, eventually obstructing the gas flow and impairing the function of the plant. Liquefaction facilities consist primarily of different varieties of refrigeration systems, depending on the technology provider, all of which cool and finally condense the high pressure natural gas to a liquefaction plant outlet temperature of minus 220 to minus 240°F. High pressure LNG is then reduced to atmospheric pressure as it passes through a control valve prior to entering the storage tanks. A small portion of the LNG vaporizes as it flashes across the valve, which cools it further to the final storage temperature of minus 260°F at near-atmospheric pressure. Even though the storage tanks are well-insulated, heat absorbed from the outside air and ground causes a small amount of the stored LNG to vaporize by evaporation, such vapor is termed “boil-off gas”. Boil-off gas and the flash gas produced across the LNG control valve are both re-compressed by the boil-off gas compressors and sent to the plant fuel gas system, exported to the natural gas distribution system, or recycled to the liquefaction unit, so that no atmospheric venting occurs.

Pretreatment and liquefaction facilities for a peak shaving plant typically are designed to meet a guaranteed net LNG production into the tank of 10 to 20 million standard cubic feet of natural gas per day (MMscfd). In a typical LNG peak shaving facility the LNG storage tanks typically have sufficient LNG inventory volume to be equivalent to approximately ten days to two weeks of equivalent gas storage at the maximum re-gasification and send-out capacity. For example, at one typical peak shaving facility located in the lower 48 states, the LNG liquefaction rate is 20 MMscfd, and the re-vaporized LNG send-out capacity is 400 MMscfd. Ten days capacity at this rate (4,000 MMscfd) equates to two LNG storage tanks each with a capacity of 90,500 cubic meters of LNG.

LNG regasification facilities typically comprise LNG pumps, which are submerged in the LNG inside the tanks. Output from the LNG pumps is routed to one or more LNG gasifiers, typically at a discharge pressure of 800-1,000 psig, which is slightly above normal gas pipeline operating pressure. In some cases, the in-tank pumps serve merely as transfer pumps or booster pumps, which supply LNG to the suction side of high-pressure send-out pumps which boost the LNG to operating pipeline pressure, sometimes in excess of 2,000 psig. Each LNG gasifier at a typical LNG peak shaving plant is a stainless steel heat exchanger. LNG is vaporized inside of tubes. Heat for the vaporization is provided by circulating a heated ethylene glycol/water solution, similar to automotive antifreeze solution, around the outside of the tubes. The glycol/water solution is heated in a separate, natural gas-fired, water-bath heater. In this heater, the solution circulates through coils submersed in a bath of hot water or hot glycol/water, where the choice of heat medium is determined by the climatic conditions. The water bath is always kept hot so that the heat input is nearly instantaneous, rather than requiring a warm-up period. Vaporized natural gas exits the vaporizer typically at 40 to 60°F and is injected into the main pipeline for distribution to downstream consumers. Alternatively, a newer type of LNG gasifier, a submerged combustion vaporizer (“SCV”) could be used, which combines the heat exchanger and the heater into a single unit with higher fuel consumption efficiency. However, SCVs are more expensive and are more typically utilized on large base load (continuous send-out capacity) LNG receiving and re-gasification terminals, where fuel efficiency is a more important consideration.

Conceptually, an alternative, lower capital cost option might be considered for peak shaving. In this alternative scenario, the Kenai LNG Plant would be converted into a minimal capacity LNG receiving and regasification terminal solely for peak shaving purposes. This would greatly reduce the required capital expenditures. This is discussed further in Section 7.4.

7.2 PRETREATMENT AND LIQUEFACTION FACILITIES

By adapting elements of the description of typical LNG peak shaving plants provided above, the Kenai LNG liquefaction plant can be converted to a peak shaving plant. For comparison purposes, the typical peak shaving liquefaction capacity of 10 to 20 MMscfd is less than one-tenth of the current 214 MMscfd liquefaction capacity at Kenai. Using one train of the “two trains in one” configuration of the Kenai plant, the capacity would be reduced to around 100 MMscfd. Normal turndown on a single train is of the order of 70 percent, i.e., 70 MMscfd, approximately twice that of a large peak shaver facility. However, operating at this rate is inefficient and the three existing LNG tanks would be filled in one month, leaving the plant on cold standby for eleven months of the year. For the purposes of this analysis, we have assumed that the existing pretreatment and liquefaction facilities are too large and inefficient to function well in peak shaving service without some major modifications. Therefore, revised pretreatment and completely new liquefaction units would be required, again designed for a rate of 20 MMscfd. The higher capacity will most likely be required for the Anchorage area due to the wide swings in seasonal demand (2.7:1) reported by ENSTAR, the local gas distribution company. These smaller liquefaction units are furnished as standard skid-mounted packaged units for ease of shipping and installation. Several prominent and well-respected manufacturers can supply these units.

Currently, the existing pretreatment facilities at the Kenai LNG plant consist of inlet scrubbers to remove liquid droplets and particulate matter. The existing scrubbers could be re-used at the lower gas processing rate. However, new internals will likely be required to maintain scrubbing efficiency. Cold inlet gas must then be heated about 40°F to approximately 80°F, depending on the amine absorbent selected for carbon dioxide removal. This preheating step ensures low amine viscosity and prevents hydrate formation from the wet, treated gas leaving the top of the amine absorber tower. The existing amine absorber tower and its associated amine stripper tower, both typically containing 20-25 distillation trays for mass transfer, can most likely be re-used. However, the distillation trays in both towers will require replacement due to the much lower gas processing rate, but this is an inexpensive modification. Pumps and heat exchangers in the amine treating unit will also likely need to be replaced with smaller equipment; again this equipment is relatively inexpensive. We assume that most of the piping can be re-used.

The amine treating unit is then followed by a cyclical molecular sieve adsorption system to remove the water vapor absorbed from amine treating and the majority of any remaining carbon dioxide. Existing molecular sieve adsorption vessels will likely need to be replaced due to the much lower gas flow to avoid channeling through the sieve. Molecular sieve adsorption is followed by a particulate filter to remove molecular sieve dust particles. The existing particulate after-filter, depending on its design, could likely be modified slightly and re-used at the lower capacity. However, the basic operation will essentially remain the same, so the current operations and maintenance personnel will be thoroughly familiar with the basic concepts of the new replacement facilities.

Each of the principal liquefaction suppliers utilizes their own proprietary liquefaction technology. For example, Black and Veatch Pritchard utilizes its PRICO™ Process, which utilizes a single multicomponent refrigerant mixture consisting of nitrogen, methane, ethane or ethylene, propane or propylene, isobutane, and isopentane. This system might be especially appropriate for the Kenai location due to its simplicity and low capital cost, and the cooler ambient temperatures, which somewhat offset the slightly lower liquefaction efficiency. High-pressure mixed refrigerant leaving the single refrigerant compressor is cooled and partially condensed in a water-cooled condenser, with water supplied by the existing cooling tower. Thereafter, vaporizing low-pressure mixed refrigerant supplies sufficient refrigeration to cool and condense the incoming natural gas feed stream as well as the high-pressure mixed refrigerant.

Another major peak shaving liquefaction supplier, CB&I typically utilizes their proprietary and patented Mixed Refrigerant Liquefier™ ("MRL") cryogenic liquefaction cycle. This system utilizes two separate closed refrigeration loops. The first is a propane refrigerant loop with the high-pressure propane from the refrigerant compressor being condensed in a cooling water condenser. Vaporizing low-pressure propane refrigerant is used to cool the incoming natural gas feed stream and to cool and partially condense the high-pressure MRL refrigerant. Vaporizing low pressure MRL refrigerant further cools and condenses both the natural gas feed and the high-pressure MRL refrigerant stream.

By way of comparison, the existing ConocoPhillips Optimized Cascade Process liquefaction cycle currently in use at Kenai utilizes three separate refrigeration loops consisting of a propane loop, followed by an ethylene loop, and finally a methane refrigeration loop. Dual parallel refrigerant compressors are installed for each loop, with variable-speed gas turbine drivers. This combination provides excellent turndown, and it might be feasible to consider re-use of the existing liquefaction facilities for peak shaving, keeping one refrigerant unit in each loop as an installed spare. However, the existing refrigeration units will be 40 years old and nearing the end of their useful service life by the time the current LNG export contract terminates in 2009. For this reason, while re-use of the existing liquefaction facilities is not considered by Stone & Webster Consultants in this evaluation, the practicability of so doing warrants further evaluation, as the potential capital cost savings could be substantial.

The existing cooling tower and all other utility and support facilities would continue to serve the revised peak shaving configuration. Stone & Webster Consultants assumes adequate electric power and other utilities and support facilities will be available for the revised plant configuration, but this assumption also would also need to be confirmed in a subsequent detailed engineering study.

7.3 REGASIFICATION AND SEND-OUT FACILITIES

As previously stated, for a typical LNG peak shaving facility the LNG storage tanks have sufficient LNG inventory volume to be equivalent to approximately ten days to two weeks of equivalent gas storage at the maximum send-out capacity. In terms of volume, each of the three 225,000 barrel LNG storage tanks at the Kenai LNG Plant holds the equivalent gas volume of 790.2 MMscf, or approximately 2,307 MMscf in total. Thus in terms of ten days storage for peak shaving, the new re-gasification and send-out facilities would be designed for a maximum send-out rate of 230.7 MMscfd, and for fourteen days of storage, the re-gasification and send-out capacity would be designed for 164.8 MMscfd. These rates are within the unit size range of typical re-gasification units being installed on most peak shaving plants being built in the U.S. and Europe.

According to the recently published South-Central Alaska Natural Gas Study[1], the current natural gas demand in the Anchorage area is 356 MMscfd for heavy industrial use and 192 MMscfd for residential and commercial use. The heavy industrial consumption refers to the liquefaction load at the Kenai plant and the feedstock supply to the Agrium Fertilizer plant. According to this same study, the daily average consumptions by these two users are 214 and 142 MMscfd, respectively. However, for this peak shaving alternate case, the two industrial users will most likely have ceased their primary operations. Therefore the peak shaving send-out capacity can be assumed to supply only needle peak shortfalls in terms of residential and commercial consumption alone. And this assumption in turn is based on the basic natural gas source being from new and/or expanded Cook Inlet gas field suppliers. According to this study, at the current production rates, even without the heavy industrial consumers, the residential and commercial demand can only be satisfied through approximately 2012, unless new natural gas supplies can be developed in the Cook Inlet area.

Based on a current annual average consumption rate of 192 MMscfd for domestic and residential consumption and a projection of 300 MMscfd by 2025, and assuming continuing production from the Cook Inlet, albeit at greatly reduced rates, it would appear that a maximum send-out capacity of approximately 400 MMscfd would ultimately be required for a converted peak shaving operation. Such as large re-gasification rate is required to meet the peak seasonal swings in demand, which can be almost three times the average summertime demand. A more definitive study of seasonal and peak gas demand would be required to better quantify the basis for the design capacity of the re-gasification facilities.

Because of the severity of the seasonal swings in demand it might also be prudent to consider a higher liquefaction capacity and/or more LNG storage inventory. While ten to fourteen days of storage might be adequate for peak shaving in the lower 48 states, double this send-out capacity might be more applicable to the Anchorage area. For example, if the new liquefaction capacity of 20 MMscfd is adopted, completely re-filling the three existing LNG storage tanks would require 115 days. Therefore, for this location it might be prudent to add an additional LNG storage tank that could be utilized for the storage from the peak shaver or for storage of an imported cargo of LNG to cover peak demand periods. A new state-of-the-art, full containment LNG storage tank, with a useable inventory of 160,000 cubic meters (approximately 3,500 MMscf) would cost approximately US$70 million, plus the cost of auxiliaries, estimated at an additional US$30 million.

The existing LNG tanker export loading pumps are capable of loading an 88,000 cubic meter tanker is eighteen hours. Therefore the loading pumps are designed to pump in aggregate the equivalent vaporized LNG capacity of 110 to 130 MMscf per hour, which is much higher than the maximum anticipated re-gasification rate (approximately 15 to 20 MMscf per hour). Thus the LNG ship loading rate is equivalent to a total liquid pumping rate of 5,000 to 6,000 cubic meters of LNG per hour, whereas the re-gasification pumping rate and the discharge pressure for ship loading are both much lower than those required for re-gasification and send-out. Therefore, new high-pressure LNG vaporizer feed pumps will be required.

Normally a world-class LNG storage tank is equipped with three in-tank pumps, two operating and one spare. However, for these much smaller tanks two 100 percent capacity, with one in each tank being a spare, is sufficient. Typically one of the pumps in at least one of the tanks is supplied with a variable frequency (speed) electric motor driver that permits the pumps to operate over a wider range of flow rates and discharge pressures. This pump is intended for other services such as re-gasification system cooling prior to actual gasification and/or possibly for LNG truck loading. For example, a LNG truck loading rack could be installed to deliver LNG for use in local commercial vehicle fleets, such as the Anchorage city bus fleet and/or the municipal garbage collection fleet. However, for purposes of this study the truck rack will not be included in the capital cost estimate, but these facilities are relatively inexpensive.

The assumed re-gasification configuration would utilize two of the six in-tank send-out pumps, each designed for approximately 75 MMscfd to feed a single shell and tube LNG gasifier, such that this combination would be capable of a total send-out capacity of 150 MMscfd. Three such sets in total would be provided. This type of LNG gasifier has a wide operating range, such that operation over the full range of perhaps 25 to 150 MMscfd each presents no turndown problems.

As noted previously, the heat input to each gasifier is supplied by a circulating glycol/water solution, which in turn is heated by a direct-fired water bath heater. Four operating centrifugal pumps, each one rated for approximately 1500 gpm, route glycol/water solution at 200°F to the two parallel gasifiers. Thus each solution pump is rated for 75 MMscfd and each gasifier is rated for 150 MMscfd. Typically the glycol solution flows through the exchanger shell and the LNG is vaporized in the exchanger tubes. Both streams typically flow co-currently (in the same direction) through the exchanger such that the coldest LNG temperature (-260°F) is opposite the warmest glycol temperature (+200°F), to minimize potential freezing problems with the glycol solution. The cooler glycol solution exits the exchangers at approximately 130°F and returns to the heaters to be re-heated to complete the circulation loop.

Once the LNG has been re-vaporized, it must then be routed through a new gas export metering station for custody transfer measurement and accounting. This station would likely consist of two to four parallel and independent metering runs. To correspond with the re-gasification scenario presented herein, each of four metering runs would be designed to accurately measure gas throughput covering a range of perhaps 25 to 100 MMscfd. Depending on the volume of gas being exported, each metering run would be activated in turn as the flow rate increased to provide a high degree of accuracy over the entire send-out capacity range.

The metering station would also contain analytical instrumentation, such as a gas chromatograph, to provide compositional analysis of the gas by individual component, such as nitrogen, methane, ethane, etc. A separate analyzer or analyzer calculation module would also be utilized to measure or calculate the higher (gross) heating value of the gas for sales purposes, as natural gas is typically sold in terms of million British Thermal Units (MMBtu). Assuming a send-out pressure of 800 to 1200 psig, the metering station and all send-out facilities would likely be designed for 1440 psig, in accordance with industry practice.

Based upon the minimal modification and revisions, no additional utilities and support facilities are contemplated, as electric power and other available utilities and services should easily accommodate the revised configuration.

7.4 ESTIMATED CAPITAL COST

The revised pretreatment facilities, including replacement of the molecular sieve unit, some new amine treating equipment, plus additional piping, instrumentation and other miscellaneous items would cost in the order of US$15 million. A new packaged 20 MMscfd liquefaction unit would cost in the order of US$50 million. New LNG send-out pumps, vaporizers, glycol solution heaters, glycol circulation pumps, and the metering station would cost in the order of US$35 million. Thus the total order-of-magnitude estimate for the conversion of the Kenai LNG Liquefaction Plant to a conventional peak shaving facility would be in the order of US$100 million for the EPC Contract scope of work. Owners' costs would add approximately 25 percent of the EPC Contract cost, or an additional US$25 million. These owners' costs would include demolition and dismantling of existing facilities not being re-used, revised FERC, environmental and other permitting and regulatory applications, preparation of a new Front End Engineering Design ("FEED") package for the new facilities, owners' personnel labor and expense costs during project development and during EPC Contract execution, contingency funding, working capital funding, interest during construction, finance fees, etc. Thus the total Project capital cost is estimated at US$125 million.

As discussed in Section 7.2, conversion of the Kenai LNG Plant into a minimal capacity LNG receiving and regasification terminal solely for peak shaving purposes would greatly reduce the required capital expenditures. Specifically, the revised pretreatment costs would be eliminated, as would the cost of the packaged liquefaction unit. The new LNG send-out pumps, vaporizers, glycol solution heaters, glycol circulation pumps, and the metering station would still be required, at a cost of approximately US$35 million. Re-location of the existing vapor return blower to permit LNG tanker unloading, plus additional miscellaneous piping, instrumentation, etc. would add around US$5.0 million. Thus the total EPC Contract cost of this option would be in the order of US$40 million. Owners' costs at 25 percent of this figure would add US$10 million, increasing the total Project capital cost to US$50 million.

7.5 PROJECT EXECUTION

The traditional peak shaving facilities as described herein will likely require an overall EPC Contract execution schedule of approximately eighteen months after permits have been approved. Schedule is largely determined by the delivery period required the packaged liquefaction unit, estimated at approximately fifteen months. Conversely, the lower cost alternate, based on the importation of LNG for peak shaving, would require lass than twelve months to fully implement, as all equipment require rather short deliveries.

Stone & Webster Consultants notes that ConocoPhillips has the in-house expertise and procedures to manage this process directly without recourse to an EPC Contractor.

7.6 REGULATORY IMPLICATIONS

Requirements for an Environmental Impact Assessment ("EIA") are defined by the U. S. National Environmental Policy Act ("NEPA"). FERC will consult with several federal, state and local agencies during the public notice and comment period of the Environmental Impact Assessment that leads to the publication of the Environmental Impact Statement ("EIS"). Issues discussed during these meetings include the federal permitting process, shipping and safety issues, project dredge and fill requirements, and any wetland impacts and mitigation.

Air emissions will need to be addressed in the EIS. Threshold quantities of NO_x and CO are defined in the Federal Clean Air Act ("FCAA"). However, air emissions from the water-bath heaters are quite low due to the use of Lo-NO_x burners, etc.

7.7 ECONOMIC ASSESSMENT

Certain economic assumptions must be made to assess the economics of the conversion of the Kenai LNG plant to a peak shaving facility,. Principal among these is that the LNG storage tank inventory is drawn down only once during the highest peak demand period, since gas would not be available from normal sources to re-fill the storage tanks during the winter period. Thus the overall conversion economics depend entirely on the sales price premium to be obtained for the supply of peaking gas, which will total 2,300 MMscf per year. The gross sales price margin is the difference between the premium price obtained by the facility from the sale of peaking gas over and above the cost of the gas purchased by the facility for liquefaction and storage. Subtracting annual operations and maintenance costs of the facility from the gross revenues derived from the peaking gas sales permits derivation of a net margin unit price in terms of US$ per Mscf. In the absence of details regarding the operations and maintenance costs for the converted facility, Stone & Webster Consultants has elected to provide a simplified economic analysis based on the required simple payout period for the total capital cost for the conversion project. Table 7.7-1 presents the simple payout period required, at various net margin unit prices, to recoup the capital investment cost of US$125 Million, based on the annual sale of 2,300 MMscf of peaking gas.

In Stone & Webster Consultants' experience, many hydrocarbon process industry companies use a simple payout period of approximately three years to screen potential project investments. For this conversion project to realize a three-year simple payout period, the required net margin price difference, after subtracting the purchase price of the gas plus the unit costs for operations and maintenance from the peaking gas sales price, would be US$18.12 per Mscf. Adding in unit O&M costs of approximately US$2.00 per Mscf (annual opex charge of US$4.6 Million), the resultant peaking gas sales price would be US$22.62 per Mscf. In Stone & Webster Consultants' opinion, this makes this scenario unviable. Notwithstanding that South Central Alaska has enjoyed the benefit of cheap gas, typically US$2.50 per Mscf, assuming that natural gas has a gross heating value of 1,000 Btu per scf, Henry Hub gas prices averaged about US$10 per Mscf over the past 12 months and at peak reached US$15 per Mscf.

Table 7.7-2 presents the simple payout period required for the alternative lower capital cost option, at various net margin unit prices, to recoup the capital investment cost of US$50 Million, based on the annual sale of 2,300 MMscf of peaking gas. For this project to realize a three-year simple payout period, the required net margin price difference would be US$7.25 per Mscf. Adding in unit O&M cost of approximately US$1.50 per Mscf (US$3.45 Million/year) to an assumed imported LNG cost of US$5.00/Mscf results in a peaking gas sales price of US$13.75 per Mscf. Clearly, this is within the range of recent gas prices in the Lower 48. In Stone & Webster Consultants' opinion, this result indicates this alternate peak shaving conversion project is much more economically viable than the more traditional configuration. Another benefit is that more than one storage tank inventory volume could be imported and sold into the local market if required, which would substantially improve the overall economics and reliability of supply during a particularly hard winter.

In the event that increased LNG storage is desired to accommodate longer duration, peak send-out periods, a new 160,000 cubic meter storage tank would be US$70 Million alone, plus a boil-off compressor, in-tank LNG transfer pumps, piping, instrumentation, etc. The total installed cost of the new tank and auxiliaries would be approximately US$100 Million. However, Stone & Webster Consultants has been informed that the bulk of the seasonal demand swings is currently being successfully handled by utilizing underground gas storage in depleted gas production fields. Thus, there would not appear to be any incentive for additional capital expenditure for additional LNG storage. Conceptually, LNG could be imported, regasified and pumped into the current underground gas storage facilities for subsequent recovery.

Table 7.7-1
Traditional LNG Peak Shaving Plant Conversion
Simple Payout Period Required to Recoup a US$125 Million CAPEX Investment
Based on Various Net Margin Unit Prices for Peaking Gas Sales

Net Margin Price US$ per Mscf	Net Income, EBITDA US$Million per Year	Simple Payout Period Required, Years
5.00	11.5	10.9
6.00	13.8	9.1
7.00	16.1	7.8
8.00	18.4	6.8
9.00	20.7	6.0
10.00	23.0	5.4
15.00	34.5	3.6
20.00	46.0	2.7
25.00	57.5	2.2

Table 7.4-2
Importation of LNG Solely for Peak Shaving
Simple Payout Period Required to Recoup a US$50 Million CAPEX Investment
Based on Various Net Margin Unit Prices for Peaking Gas Sales

Net Margin Price US$ per Mscf	Net Income, EBITDA US$Million per Year	Simple Payout Period Required, Years
1.00	2.3	21.7
2.00	4.6	10.9
3.00	6.9	7.2
4.00	9.2	5.4
5.00	11.5	4.3
6.00	13.8	3.6
7.00	16.1	3.1
8.00	18.4	2.7
9.00	20.7	2.4
10.00	23.0	2.2

7.8 CONCLUSIONS

Stone & Webster Consultants has considered two options for the conversion of the Kenai LNG plant into a peak shaving facility. The first option was a traditional peak shaving facility whereby feed gas to the new facility would be provided by expanded Cook Inlet production. This option includes revised pretreatment facilities, including replacement of the molecular sieve unit, some new amine treating equipment, plus additional piping, instrumentation and other miscellaneous items, costing US$15 million. A new packaged 20 MMscfd liquefaction unit would cost US$50 million. New LNG send-out pumps, gasifiers, glycol solution heaters, glycol circulation pumps, and the metering station would cost US$35 million, for a total EPC Contract cost in the order of US$100 million. Owners' costs, including contingency would add approximately 25 percent of the EPC Contract cost, or an additional US$25 million for a total capital cost of US$125 million.

A lower capital cost option for peak shaving would entails conversion of the Kenai LNG Plant into a minimal capacity LNG receiving and regasification terminal solely for peak shaving purposes. Under this scenario, the revised pretreatment costs and the cost of the packaged liquefaction unit would be eliminated. New LNG send-out pumps, gasifiers, glycol solution heaters, glycol circulation pumps, and the metering station would cost US$35 Million. Re-location of the existing vapor return blower to permit LNG tanker unloading, plus additional miscellaneous piping, instrumentation, etc. would add US$5.0 million. The total EPC Contract cost of this option is estimated at approximately US$40 million. Owners' costs at 25 percent of this figure would add US$10 million, increasing the total Project capital cost to US$50 million.

The revenue to be derived from either conversion would be the peaking gas sales from one single LNG storage tank inventory volume of 2,300 MMscf of gas. For the conventional project to realize a three-year simple payout period for the total capital expenditure of US$125 million, the required net margin price difference, would be US$18.12 per Mscf. Adding in unit O&M costs of approximately US$2.00 per Mscf (annual OPEX charge of US$4,600,000), the resultant peaking gas sales price would be US$22.62 per Mscf. In our opinion, this makes this scenario unviable.

For the alternate peaking operation project, based on use of imported LNG, to realize a three-year simple payout period, the required net margin price difference would be US$7.25 per Mscf. Adding unit O&M cost of approximately US$1.50 per Mscf (US$3.45 million per year), plus the imported LNG cost of US$5.00 per Mscf results in a gross peaking gas sales price of US$13.75 per Mscf, a more viable result. Another benefit is that more than LNG cargo could be imported enabling peak demand during a protracted cold spell to be accommodated.

Stone & Webster Consultants has been informed that the bulk of the seasonal demand swings is currently being successfully handled by utilizing underground gas storage in depleted gas production fields. Thus, there would appear to be no incentive for additional CAPEX for additional LNG storage. Use of the current underground gas storage facilities could augment the use of the Kenai LNG plant as a LNG peak shaving facility.

8.1 PREAMBLE

This section of the report discusses conversion of the Kenai LNG Plant to a base-load LNG Receiving and Regasification Terminal. The conversion could occur directly from the current configuration or from interim conversion to a LNG Peak Shaving Facility.

Potential sources of LNG for importation into Alaska are listed in Table 8.1-1 below:

Table 8.1-1
Potential Sources of LNG

Project	Country	Start Date
Tangguh	Indonesia	2008
Gorgon	Australia	2008-2010
RasGas/Qatargas	Qatar	1997
Greater Sunrise	Australia/ East Timor	2009
Pacific	Peru	2009
Tiga	Malaysia	2003
Brunei	Brunei	1972
Bontang	Indonesia	1977
North West Shelf (Train 5)	Australia	2007
Darwin LNG (Bayu Undan)	Australia/ East Timor	2006
Qalhat LNG	Oman	2005
Yemen	Yemen	2010
Sakhalin	Russia	2007/8
Iran	Iran	2010

The source of LNG may determine a need to install extraction facilities for LPG to satisfy a maximum heating value specification for regasified LNG for export. However, for the purposes of this study, these LPG removal facilities are assumed to be unnecessary.

A typical LNG receiving and regasification terminal is designed to receive LNG carrier cargoes exported from overseas base load liquefaction plants and exporting terminals. The LNG is then stored in large LNG storage tanks and re-vaporized at a more or less continuous send-out rate for distribution into the existing natural gas pipeline distribution network. Several LNG receiving and regasification terminals have been announced and are under various stages of development and construction in the lower 48 states and on the upper east and west coasts of Mexico and Canada. These new terminals are designed to receive, re-vaporize, and send-out natural gas at rates ranging from 500 to 4,000 MMscfd.

Normally the terminal owner/operator will have contracted with one or more terminal use customers, who are responsible for importing the LNG and for marketing the exported re-vaporized natural gas. These terminal use agreements would typically be for parcels of 500 MMscfd or more in the Lower 48 States, Mexico or Canada; however, lower commitments would likely apply to a Kenai LNG receiving and regasification terminal due to the smaller off-take market in South-Central Alaska. A 500 MMscfd terminal use agreement with ENSTAR Gas Company, for example, would be equivalent to the proposed volume of gas to be transported from the new ANGP Spur Line from the Fairbanks/Delta Junction area into the Cook Inlet area. Recent annual average consumption of 548 MMscfd is dominated by industrial users, namely 214 MMscfd by the Kenai LNG plant and 142 MMscfd by the Agrium fertilizer plant. Domestic and residential demand, including power generation, averages only 192 MMscfd, but is projected to grow to 300 MMscfd by 2025. Without Kenai LNG as a user of gas, demand would decrease to 334 MMscfd with a growth potential of 450 MMscfd. Based on proven reserves, by 2014 production from the Cook Inlet will have declined to below 190 MMscfd. Thus in addition to peak supply concerns discussed in Section 7, by 2014 additional base supplies of gas will be required to support domestic and residential consumption. Market forces will determine whether Agrium can continue in operation based on imported LNG as a gas source. For the purpose of this evaluation, we have assumed that the long-term natural gas requirements for the South-Central Alaska area should be based only on growth projections for the residential and commercial markets.

ENSTAR Gas Company has reported that the peak consumption rate varies by a factor of approximately 2.7:1 between the summertime low to the wintertime high. For the purpose of this assessment, we have assumed an average summertime rate of 140 MMscfd and a corresponding wintertime rate of 380 MMscfd. This simplified analysis must be confirmed by actual daily, weekly and monthly consumption rates for the local distribution system before a terminal is designed. However, on this basis, the terminal send-out capacity should be sized for an average wintertime export capacity of 400 MMscfd to service the residential and light commercial needs of the area.

The first consideration in evaluating the need to convert the Kenai LNG facility to a regasification facility will be the likelihood of finding and developing additional natural gas production within the Cook Inlet. Assuming such gas is not available, the existing Kenai liquefaction and export terminal can be converted into a LNG receiving and regasification terminal to satisfy either the short-term gas supply needs until the Spur Line can be constructed and commissioned, or for the long-term needs of South-Central Alaska in the event that the Spur Line is not constructed. Therefore, any decision on converting the Kenai LNG plant into a peak shaving facility or into a main LNG receiving and regasification terminal is likely to be predicated on the likelihood that the Spur Line will be constructed.

8.2 LNG RECEIVING FACILITIES

The basic infrastructure of the Kenai liquefaction plant should suffice for most of the LNG receiving requirements, except that the current LNG storage volume is low, especially for long-term service. Each of the three small existing LNG storage tanks has a service volume of only 36,000 cubic meters of liquid storage, or a combined equivalent gas storage volume of 2,300 MMscf. The current LNG carriers servicing the Kenai facility can transport 88,000 cubic meters of LNG, which are small parcels compared with the current LNG carrier fleet, most of which has a capacity in excess of 124,000 cubic meters. The two current vessels should be adequate in the near-term, since they currently export about 200MMscfd of gas equivalent. It may be desirable to import a small number of spot cargoes during the summer months, regasify these and bolster the underground storage caverns so that the gas can be used during winter peak demand. While certain of the new U.S. Gulf Coast LNG terminals are being constructed to receive the anticipated new super-sized LNG carriers designed for cargo sizes up to 260,000 cubic meters, we do not anticipate LNG carriers in excess of 138,000 cubic meters being used to supply Kenai due to draft retrictions. Special provisions may apply to any supplementary cargo provided during the winter months when the Cook Inlet has broken ice. However, we note that similar conditions apply to the relatively close Sakhalin II LNG baseload facility on the southern tip of Sakhalin Island, Russia. In addition, supply from the Sakhalin II LNG facility would entail a shorter import voyage than the current export voyage to Japan. Thus the current LNG carriers, augmented by perhaps one or two additional smaller size LNG carriers for spot cargoes and as imports increase over time, may therefore suffice for the long-term, assuming they remain code and regulatory compliant.

Notwithstanding the observation with respect to underground storage, the marked increase in demand that can occur in the winter months might tend to indicate that more storage is desired to meet peak demands.

In this case, Stone & Webster Consultants assumes the addition of a new state-of-the-art, full-containment LNG storage tank sized for approximately 160,000 cubic meters. As indicated previously, a LNG storage tank this size would cost approximately US$70 million, plus auxiliaries consisting of a new boil-off gas compressor, in-tank transfer pumps, piping, and instrumentation, etc., which would increase the total overall cost of the complete new tank installation to approximately US$100 million. A larger additional storage tank would be especially helpful in unloading the newer larger LNG carriers should the existing carriers in use be retired or otherwise replaced.

The current storage capacity of 2,300 MMscf equates to a “storage to send-out” capacity ratio of 5.75, based on a typical wintertime send-out demand of 400 MMscfd for residential and domestic consumption, including power generation. A ratio of 6.0 is considered to be desirable for U.S. Gulf Coast (“USGC”) receiving terminals, but ratios as low as 4.0 have been proposed. In Stone & Webster Consultants’ opinion, the higher ratio would be more appropriate for South-Central Alaska due to the more severe climate and the likelihood of longer peak send-out durations. This peak demand is assumed to be approximately 500 MMscfd. At the maximum anticipated send-out rate of 500 MMscfd, the respective ratio would be 4.6, which should be acceptable for short-duration peak send-out periods. The addition of a new 160,000 cubic meter (3,500 MMscf natural gas equivalent) LNG storage tank would increase the total gas storage volume to 5,800 MMscf, and would result in a “storage to send-out” ratio of 11.6 even at the anticipated peak export capacity of 500 MMscfd. Therefore, Stone & Webster Consultants assumes for the purposes of this preliminary study that the new tank will not be included in the plant conversion scope of work.

The existing LNG loading facilities are capable of loading an 88,000 cubic meter LNG carrier in 18 hours, therefore the current loading pumps, transfer piping, and loading arms can accommodate a loading rate of 5,000 to 6,000 cubic meters per hour. Stone & Webster Consultants has no specific information regarding the current LNG carrier shipboard unloading pumps. Assuming the current unloading rate is equivalent to the loading rate, the existing loading arms can be re-used for imports as well as exports. Therefore the primary modification required to convert from loading to unloading would be the relocation of the existing vapor return blowers to transfer displaced LNG vapor from the storage tank to the LNG carrier, during the unloading operation, such that the vapor flow direction would be reversed. This is considered a very minor modification.

However, the newer LNG carriers already in service with an average cargo capacity sized for 140,000 cubic meters and larger can unload at average rates of approximately 12,000 cubic meters per hour. Should these larger LNG carriers be used, Stone & Webster Consultants would assume it to be prudent to add parallel unloading lines to handle the higher unloading rates and, as well as newer, larger unloading arms. These larger unloading arms would cost approximately US$6.5 Million in purchase price, plus engineering and construction costs to install them. The total installed cost of these additional revisions, if required, would be approximately US$25 Million. These additional costs have been excluded from this preliminary study.

8.3 REGASIFICATION AND SEND-OUT FACILITIES

The LNG vaporizer utilized at a typical LNG receiving and regasification terminal operates continuously, as opposed to infrequently as is the case for a peak shaving plant. Modern receiving and regasification terminals in cold climates typically utilize submerged combustion vaporizers (“SCV”). These combine the heat exchanger and glycol solution circulating pumps with the direct-fired heater into a single unit with significantly higher fuel consumption efficiency. This higher fuel efficiency is due to the submerged combustion technology. Combustion air is compressed by a high-pressure combustion air blower, mixed with natural gas fuel and combusted at elevated pressures sufficient to permit the combustion gases to be "bubbled" through a large water bath before exiting the SCV flue gas stack. LNG is vaporized inside tubes immersed in the SCV water bath. This submerged combustion process results in much higher efficiency because water vapor produced as a combustion by-product is condensed by the water bath, thereby utilizing the gross heat of combustion from the fuel gas, rather than just the net heat of combustion. In a conventional heater, the water vapor produced by combustion by-product exits the heater flue gas stack as a vapor, thereby losing the latent heat of condensation otherwise available from that water vapor. While the SCV has a higher combustion efficiency, it is also more expensive than the simple exchanger and water bath heater combination used for peak shaving. However, since the added fuel efficiency is obtained on a continuous basis, SCVs are more typically utilized for main LNG receiving and regasification terminals, where higher fuel efficiency, and thus reduced operating cost, is an important consideration.

Stone & Webster Consultants has assumed that send-out facilities will be based upon installing two new, low-pressure in-tank transfer pumps inside each existing LNG storage tank. Each of these pumps would be designed for an equivalent vaporized gas capacity of 100 MMscfd (830 gpm) at a discharge pressure of approximately 100 psig. The purchase price for these pumps will be approximately US$100,000 each. Thus only four of the installed six pumps will meet the average residential and domestic wintertime demand, and five of the six pumps could meet the maximum anticipated peak wintertime demand of 500 MMscfd.

In-tank pumps would feed a low-pressure LNG send-out suction manifold, which would supply a minimum of five parallel tandem regasification units, each consisting of a high-pressure send-out pump and a submerged combustion vaporizer. The fifth tandem unit will normally serve as a spare, but could be activated to meet higher peak demand during the winter. However, this installation would not provide any spare capacity. The equipment purchase price for each high-pressure send-out pump is approximately US$400,000 and each vaporizer is US$800,000. Therefore, higher onstream availability could be achieved by adding a sixth tandem send-out unit, which would provide a spare unit even under the peak wintertime demand condition. Stone & Webster Consultants has assumed an additional sixth tandem unit. The additional capital cost for this item is provided separately for evaluation purposes.

Once the LNG has been re-vaporized, it must then be routed through a new gas export metering station for custody transfer measurement and accounting. This station would likely consist of two to four parallel and independent metering runs. To correspond with the regasification scenario presented herein, each of four metering runs would be designed to accurately measure gas throughput covering a range of perhaps 50 to 200 MMscfd. Depending on the volume of gas being exported, each metering run would be activated in turn as the flow rate increased to provide a high degree of accuracy over the entire send-out capacity range.

The metering station would also contain analytical instrumentation, such as a gas chromatograph, to provide compositional analysis of the gas by individual component, such as nitrogen, methane, ethane, etc. A separate analyzer or analyzer calculation module would also be utilized to measure or calculate the higher (gross) heating value of the gas for sales purposes, as natural gas is typically sold in terms of million Btu (MMBtu). Assuming a send-out pressure of 800 to 1200 psig, the metering station and all send-out facilities would likely be designed for 1440 psig, in accordance with industry practice.

Based upon the proposed modifications and revisions, no additional utilities and support facilities are contemplated, as electric power and other available utilities and services should easily accommodate the revised configuration. However, this issue should be confirmed by a more thorough engineering study.

However, as noted previously, the SCVs do produce water as a combustion by-product which must treated prior to marine disposal. Water from the SCVs is somewhat acidic due to dissolved carbon dioxide (carbonic acid), which must be neutralized prior to disposal of the effluent to the sea. Caustic soda solution (sodium hydroxide) or soda ash solution (sodium bicarbonate) can be added to the SCV water to achieve the required neutral pH value necessary to satisfy the water effluent disposal permit. The choice between the two would depend on availability, purchase price, shipping cost, etc.

8.4 PROJECT EXECUTION

Receiving and regasification facilities as described herein will likely require an overall EPC Contract execution schedule of approximately eighteen months after permits have been approved. The schedule length is largely determined by the delivery period required the packaged SCV units, estimated at approximately fifteen months. However, should the terminal owner/operators desire additional storage, the potential new 160,000 cubic meter, full-containment LNG storage tank would require a minimum completion period of 36 to 42 months following permit approvals.

8.5 REGULATORY IMPLICATIONS

Requirements for an Environmental Impact Assessment ("EIA") are defined by the U. S. National Environmental Policy Act ("NEPA"). FERC will consult with several federal, state and local agencies during the public notice and comment period of the Environmental Impact Assessment that leads to the publication of the Environmental Impact Statement ("EIS"). Issues discussed during these meetings include the federal permitting process, shipping and safety issues, project dredge and fill requirements, and any wetland impacts and mitigation.

Air emissions will need to be addressed in the EIS. Threshold quantities of NO_x and CO are defined in the Federal Clean Air Act ("FCAA"). Air emissions from the SCV units are the most critical issue from a permit compliance standpoint. However, the latest Best Available Control Technology ("BACT") indicates that emissions with a maximum NO_x concentration of 30 ppmv is sustainable, as represented by the major SCV manufacturers.

8.6 ESTIMATED CAPITAL COST

Basic conversion of the Kenai liquefaction plant to a receiving and regasification terminal would consist of new in-tank transfer pumps in each of the three existing LNG storage tanks. The installed cost for the in-tank pumps would be approximately US$4.0 million. Regasification would be achieved through the addition of five new tandem regasification units, with each tandem unit consisting of a high-pressure send-out pump and a SCV. The installed cost for these five tandem units would be approximately US$27.5 million. The sixth tandem regasification unit could be added for an estimated capital expenditure addition of US$5.5 million. As stated previously, Stone & Webster Consultants assumes that the addition of the sixth regasification unit would be required to ensure reliable supply during periods of peak demand.

The cost for the new send-out metering station, high-voltage switchgear, water neutralization and disposal facilities, re-location of the existing vapor return blower, plus additional miscellaneous piping, instrumentation, etc. would add approximately US$13.0 million. Thus the EPC Contract cost for the basic receiving and regasification terminal conversion is estimated at US$50.0 million. Owners' costs equivalent to 25 percent of the EPC Costs, or US$12.5 million, would yield a total Project capital cost estimate of US$62.5 million. Therefore, the total capital cost to complete the conversion of the Kenai liquefaction plant to a LNG receiving and regasification terminal is summarized in Table 8.6-1:

Table 8.6-1
LNG Terminal Capital Cost Estimate

Expenditure Description	**US$ Million**
New 160,000 m^3 Full-Containment LNG Storage Tank, plus Auxiliaries	n/a
Two New In-Tank Transfer Pumps in Each Existing LNG Tank (6 total)	4.0
Five (Minimum) Tandem Send-Out Regasification Units	27.5
A sixth (Recommended) Tandem Send-Out Regasification Unit	5.5
Miscellaneous Treating Facilities, Equipment, Piping and Instrumentation	13.0
Estimated EPC Contract Cost	**50.0**
Owners' Cost @ 25 % of EPC Contract Cost	12.5
Total Estimated Project Capital Cost	**62.5**

8.7 ECONOMIC ASSESSMENT

During the initial operations period following completion of the conversion project, the average annual export rate is expected to remain at approximately 200 MMscfd. In terms of project revenue, the USGC LNG receiving and regasification terminals typically charge a unit tolling fee. Tolling fees for a USGC location are around US$0.35 per Mscf, applying a 1.4 conversion factor for Alaska yields a tolling fee of approximately US$0.45 per Mscf. Typically, tolling agreements also contain provisions which allow the terminal owner/operator to consume around two percent of the imported LNG for internal fuel gas purposes. This eliminates most of the typical variable costs to the operator. The net result is that the tolling fee covers all operations and maintenance costs plus debt service, and/or return on equity to the owner/operator, as is appropriate. However, this scenario assumes high send-out capacities, where a substantial percentage of the installed facilities are being utilized on a continuous send-out basis. Where this is not the case, there is typically a separate storage fee.

Based on previous experience, Stone & Webster Consultants would estimate the actual operations and maintenance ("O&M") cost for the converted facilities at approximately US$12 million per annum. The O&M cost for such a facility is higher than for the imported LNG peak shaving scenario discussed in Section 7, because this facility would operate year-round, whereas the peak shaving facility would typically deliver gas during the two coldest months of the year. Therefore, additional revenues to provide return on equity can only be realized after the US$12 million O&M cost commitment has been met. The gross revenues, from a tolling fee of US$0.45 per Mscf are US$32,850,000 per annum, based on the average annual send-out rate of 200 MMscfd. After covering the annual O&M cost, the net revenues are US$20,850,000. Application of these net revenues toward the total Project capital cost of US$62.5 Million results in a simple payout period of 3.0 years. This equates to the analysis applied to the previous commercial options for conversion of the Kenai LNG plant, which were also based on a three-year simple payout analysis. Therefore, Stone & Webster Consultants would conclude, based on this preliminary analysis, that this option would appear to be economically viable.

Another way of evaluating this scenario is to take a similar approach to the economic assessment utilized in Section 7 whereby the gas sales revenue and the exported gas sales price are be built-up to provide for a three-year simple payout period as before. To illustrate, the exported gas volume of 200 MMscfd equates to 73,000,000 Mscf per annum. The estimated annual O&M cost of US$12 million per annum thus results in a unit O&M cost of US$0.165 per Mscf (US$12 million/73,000,000 Mscf). To meet the three-year payout requirement, revenues must also include US$20,833,333 per annum (US$62.5 million/3), which equates to US$0.285/Mscf on a unit basis (US$20,833,333/73,000,000 Mscf). Assuming an imported LNG cost of US$5.00 per Mscf, the gross sales price required to satisfy a three-year simple payout and meet O&M cost obligations is thus US$5.45 per Mscf (5.00 +0.165 + 0.285).

Thus for comparison purposes, the unit O&M cost assessment plus the unit return on equity assessment together equal the US$0.45 per Mscf tolling fee. Therefore the overall economic assessment approach utilized herein is consistent and reasonable. The gross exported gas sales price example of US$5.45 per Mscf is a viable market rate. This same tolling fee can also be utilized to examine higher costs for imported LNG and the resultant exported gas sales price, as well as increased LNG receiving and regasification capacity scenarios.

8.8 CONCLUSIONS

The first consideration in evaluating the need to convert the Kenai LNG facility to a regasification facility will be the likelihood of finding and developing additional natural gas production within the Cook Inlet. Assuming such gas is not available, the existing Kenai liquefaction and export terminal can be converted into a LNG receiving and regasification terminal to satisfy either the short-term gas supply needs until the Spur Line can be constructed and commissioned, or for the long-term needs of South-Central Alaska in the event that the Spur Line is not constructed. Therefore, any decision on converting the Kenai LNG plant into a peak shaving facility or into a main LNG receiving and regasification terminal is likely to be predicated on the likelihood that the Spur Line will be constructed.

Conversion of the Kenai liquefaction plant to a receiving and regasification terminal would include new in-tank transfer pumps in each of the three existing LNG storage tanks at an installed cost of US$4.0 million. Regasification would be provided with the addition of six new tandem regasification units, with each tandem unit consisting of a high-pressure send-out pump and a SCV. The total installed cost for these units would be US$33.0 million. The cost for the new send-out metering station, high-voltage switchgear, water neutralization and disposal facilities, re-location of the existing vapor return blower, plus additional miscellaneous piping, instrumentation, etc. would add approximately US$13.0 million. Thus the EPC Contract cost for the basic receiving and regasification terminal conversion is estimated at US$50.0 million. Owners' costs equivalent to 25 percent of the EPC Costs, or US$12.5 million, would yield a total Project capital cost estimate of US$62.5 million.

Based on previous experience, Stone & Webster Consultants would estimate the actual operations and maintenance ("O&M") cost for the converted facilities at approximately US$12 million per annum. The gross revenues, from a tolling fee of US$0.45 per Mscf are US$32,850,000 per annum, based on the average annual send-out rate of 200 MMscfd. After covering the annual O&M cost, the net revenues are US$20,850,000 per annum. Application of these net revenues toward the total Project capital cost of US$62.5 million results in a simple payout period of three years. This equates to the analysis applied to the previous commercial options for conversion of the Kenai LNG plant, which were also based on a three-year simple payout analysis. Therefore, Stone & Webster Consultants would conclude, based on this preliminary analysis, that this option would appear to be economically viable.

In support of this analysis, the gas sales revenue and the exported gas sales price can be built-up to provide for a three-year simple payout period as before. To illustrate, the exported gas volume of 200 MMscfd equates to 73,000,000 Mscf per annum. The estimated annual O&M cost of US$12 million per annum thus results in a unit O&M cost of US$0.165 per Mscf. In order to meet the 3-year payout requirement, revenues must also include US$20,833,333 per annum (US$62.5 Million/3), which equates to US$0.285 per Mscf. Assuming an imported LNG cost of US$5.00/Mscf, the gross sales price required to satisfy a three-year simple payout and meet O&M cost obligations is thus US$5.45 per Mscf (5.00 +0.165 + 0.285).

Thus for comparison purposes, the unit O&M cost assessment plus the unit return on equity assessment together equal the US$0.45 per Mscf tolling fee. Therefore the overall economic assessment approach utilized herein is consistent and rational. The calculated exported gas sales price of US$5.45 per Mscf over the LNG purchase price of US$5.00 per Mscf is viable. The same tolling fee can also be utilized to examine higher costs for imported LNG and the resultant exported gas sales price, as well as increased LNG receiving and regasification capacity scenarios.

9.1 PREAMBLE

In addition to the options considered in Sections 5 through 8, there is another potential option for the commercial future of the Kenai LNG plant that does not involve LNG. For this option to be viable, Stone & Webster Consultants assumes that the new ANGP pipeline from the North Slope would be constructed with a treated gas export capacity of approximately 4,500 MMscfd. Treatment at the North Slope prior to transmission is assumed to include bulk carbon dioxide removal, followed by gas dehydration, to meet Canadian and U.S. interstate natural gas pipeline specifications for impurities.

Stone & Webster Consultants then assumes that the treated gas stream undergoes additional cryogenic processing at the Fairbanks or Delta Junction to recover LPG and heavier hydrocarbons consisting of propane, butanes, and natural gasoline. This option also includes the installation of two new pipelines from this new gas processing plant to the Cook Inlet area. One would be a gas pipeline with an anticipated capacity of up to 500 MMscfd to meet the peak seasonal residential and light commercial demands going forward. The second pipeline would be a mixed LPG pipeline that would transport the recovered hydrocarbon liquids to a new fractionation plant to be located at the Kenai LNG plant site. This plant would fractionate or separate the LPG mixture into finished propane, butane, and natural gasoline products for export and/or domestic Alaskan consumption.

Lastly, if no future commercial options appear to be viable for the Kenai LNG plant, the entire facility will be demolished in conjunction with salvage operations by a professional demolition company. Both of these two other alternatives are discussed in this section of the report.

9.2 CONVERSION TO A LPG FRACTIONATION PLANT

Detailed evaluation of the potential cryogenic gas processing plant to be located at the Fairbanks or Delta Junction is beyond the scope of this study. However, for the purposes of this preliminary evaluation it is assumed to be comprised of four parallel gas processing trains, each designed to recover approximately 98 percent of the incoming propane content in the feed gas being processed, plus essentially 100 percent of the heavier hydrocarbons. These gas processing trains could also be designed to recover a significant quantity of ethane, as long as the resultant combined residue gas stream retained a minimum gross heating value of 1,000 Btu per scf after incremental ethane recovery. Assuming a 98 percent propane recovery level plus 100 percent recovery for the heavy hydrocarbons, the compositions of the inlet feed gas, the resultant residue gas stream to be sent to the Lower 48 States, and the resultant mixed LPG liquid stream to be sent to the new LPG fraction plant at Kenai are shown in Table 9.2-1.

Typically, the owners of the treated gas from the North Slope would expect compensation for the reduced heat content of the residue gas due to the liquid hydrocarbon removal. The bottom row of Table 9.2-1 lists the heat content of the primary cryogenic plant streams. Heat content in the mixed liquid product stream is calculated at 216,467 MMBtu per day. Thus if the lower 48 export gas sales price is, US$5.00/MMBtu for example, the owners would receive approximately $1,082,335 per day in reduced heating value compensation. To justify the cost of the gas processing trains and the downstream fractionation plant, this cost for reduced gas heat content would have to be offset by the incremental revenues from liquid product sales from the Kenai Fractionation plant. An order of magnitude capital cost for the cryogenic gas processing facilities only would be approximately US$450 million.

The Kenai fractionation plant would consist of an inlet surge drum to receive the mixed LPG stream from the liquids pipeline. This mixed LPG stream would then be fractionated in a depropanizer tower, producing propane product as the distillate or overhead product. Bottoms product from the depropanizer would feed the new debutanizer tower. A mixture of isobutane and normal butane would comprise the distillate product stream, and a light natural gasoline stream would comprise the bottom product from the debutanizer. Existing utility systems would be utilized to support the new product fractionation facilities, including fuel gas and cooling water, etc., so additional utility system investment should be minimal. A representative fractionation plant material balance is presented in Table 9.2-2.

No further product treatment is anticipated for any of the fractionation plant products as a result of the very low sulfur content of the mixed LPG fractionation plant feed stream, and because it is fully dehydrated. However, the light gasoline product stream will have a true vapor pressure of approximately 13.3 psia. We would expect this to be stored in a new pressurized 10,000 barrel spherical storage tank. The use of pressurized storage provides protection against potentially higher vapor pressure natural gasoline products.

Propane and butane products could be stored in the existing Kenai LNG storage tanks. A new, closed-loop propane refrigeration system would be installed to cool the propane and butane products to their atmospheric storage temperatures prior to entering the tanks, and to condense the respective boil-off gas streams. Two of the three existing LNG storage tanks could be allocated to propane storage, with the third tank utilized for butane storage. Each of the LNG storage tanks has a capacity of 225,000 barrels. Therefore two tanks would provide approximately eight days of propane storage, which should be adequate for shipping logistics. The third tank would provide almost 37 days of storage for the butane product, which is much more than required.

An order of magnitude capital cost for the new LPG Fractionation Plant, plus other expected plant revisions, at Kenai would be approximately US$200 million.

Stone & Webster Consultants notes that the resultant residue gas following propane recovery has a higher heating value of approximately 1,031 Btu per scf, which indicates that ethane recovery to feed a future olefins plant is a possibility. In the event that the cryogenic gas processing plants instead were to be designed to recover ethane in addition to the propane and heavier hydrocarbons, preliminary calculations indicate that up to 70 percent of the ethane could be recovered as liquid product. The remaining ethane in the residue gas would be sufficient such that the ultimate residue gas stream to be shipped to the Lower 48 States would still meet the minimum required higher heating value of 1,000 Btu per scf. However, the amount of ethane recovered at the 70 percent recovery level is much more than needed to provide feedstock to a world-scale olefins plant.

Table 9.2-1
Fairbanks Cryogenic Gas Processing Plant
Preliminary Material Balance

Component	**Treated Gas From North Slope Gas Vol. Percent**	**Extraction Plant Residue Gas Gas Vol. Percent**	**Kenai Fractionation Mixed LPG Feed Liquid Vol. Percent**
Nitrogen	0.6907	0.7037	
Carbon Dioxide	1.500	1.5282	
Methane	90.3363	92.0351	
Ethane	5.6345	5.7000	2.04
Propane	1.6195	0.0330	84.13
Iso-Butane	0.0854		5.37
N-Butane	0.1077		6.53
Iso-Pentane	0.0094		0.66
N-Pentane	0.0087		0.61
Hexanes	0.0046		0.36
Heptanes Plus	0.0033		0.28
Total	100.0000	100.0000	100.00
Gas Flow, MMscfd	4,500	4,417	
Liquid Flow, bpsd			55,566
Molecular Weight	17.89		
HHV, Btu/scf	1060.27	1031.25	2602.86
Total Heat Content MMBtu/Day	**4,771,215**	**4,554,748**	**216,467**

Table 9.2-2
New Kenai LPG Fractionation Plant
Preliminary Material Balance
Barrels Per Stream Day

Component	**Fairbanks LPG Feed Mix**	**Propane Product**	**Butane Product**	**Gasoline Product**
Ethane	1137	1137		
Propane	46749	46632	117	
Iso-Butane	2986	728	2257	
N-Butane	3630		3614	16
Iso-Pentane	368		122	246
N-Pentane	337			337
Hexanes	202			202
Heptanes Plus	158			158
Total	**55566**	**48497**	**6110**	**959**

From the standpoint of overall economics, this option might not be viable in terms of selling the LPG product into the U.S. west coast markets because, in the USA, LPG prices are typically tied directly to natural gas prices. Over the past year, natural gas prices on the USGC have averaged approximately US$10 per MMBtu and are currently around US$6.3 per MMBtu. Table 9.2-3 below lists the equivalent

LPG component prices on a US$ per gallon basis that is equivalent to a natural gas price of US$6.50 per MMbtu. There appears to be little economic incentive for recovering LPG components from natural gas other than to comply with natural gas maximum allowable heating value specifications and or hydrocarbon dewpoint specifications. However, at likely lower gas prices for North Slope gas, there may be sufficient LPG price mark-up in the Japanese or other Far East markets to justify such an investment. A marketing analysis of this type is beyond the scope of this study.

Table 9.2-3
LPG Heating Value Cost vs Product Price Comparisons

LPG Component	Liquid HHV Btu/Gallon	Basis: $13.00/MMbtu LPG Cost, $/Gallon
Methane	59729	0.39
Ethane	65727	0.43
Propane	90823	0.59
Iso-Butane	98913	0.64
N-Butane	102909	0.67
Iso-Pentane	108754	0.71
N-Pentane	110080	0.72
Hexane	115064	0.75
Heptane	118623	0.77
Natural. Gasoline		

9.3 DEMOLITION AND SALVAGE OPERATIONS

If none of the future commercial options presented herein appear to be acceptable to the current owners of the Kenai LNG Plant, Phillips and Marathon, the entire facility likely would be demolished in conjunction with salvage operations by a professional demolition company. There are many highly reputable firms available for these types of services, and no doubt both owner companies are quite familiar with these operations. The extent of the demolition and salvage operation would be to completely dismantle the entire complex, including foundations and underground piping. Demolition would also include any required soil remediation, although we do not anticipate that this is likely. The two owner companies would bear the cost of these operations themselves.

10.1 PREAMBLE

In this section of the report, Stone & Webster Consultants discusses the various options that have been considered in the previous sections of this report and how external factors may impact the eventual outcome of the future of the Kenai LNG plant and the associated issue of the future of gas supplies to the South-Central Alaska region.

10.2 RESPONSIBILITY TO SHAREHOLDERS AND STAKEHOLDERS

ConocoPhillips and Marathon have specific duties of care to their respective shareholders. This responsibility in itself may dictate different courses of action by the partners in the facility. In addition, these two companies have implicit responsibilities to stakeholders in their areas of operation. Stakeholders include but are not limited to their staff, federal and state governments, their suppliers, their customers and their neighbors. In addition, stakeholders include the global community when pristine natural habitats can or will be impacted by an oil or gas development.

10.3 GAS SUPPLY TO SOUTH-CENTRAL ALASKA

Gas supply to South-Central Alaska is clearly a cause for concern to the local population. This concern relates not only to the magnitude and associated life of the existing reserves but also the ability to meet short-term (peak) demands. Alaska experiences seasonality in demand associated with winter heating needs. Conversely, the southern states of the US experience seasonality demand associated with summer cooling needs.

With respect to longer term supply, it is by no means certain that the supply situation is as dire as current proven reserves indicate. As discussed in Section 3, there has been little specific gas exploration over the past thirty years due to the oversupply of gas within the region. The Cook Inlet is unusual in that the distribution of gas discoveries does not fit the usual pattern, termed a log-normal distribution. Put simply, there should be a large number of small fields, a smaller number of medium sized fields an a few large fields within a given basin. In the case of the Cook Inlet, the large fields and some of the expected medium fields have been discovered, but numerous small fields have not been discovered. To date, the established reserves represent a total volume of original gas in-place (“OGIP”) of 10 trillion cubic feet. Approximately, 85 percent of this is expected to be recoverable, hence the total recoverable reserves of 8.5 trillion cubic feet. Statistically, the expectation is that the Cook Inlet basin contains 25 to 30 trillion cubic feet of OGIP. This in turn suggests that there is an additional 13 to 17 trillion cubic feet of recoverable gas to be discovered. The decline in proven reserves, couple with this expectation of gas awaiting discovery explains why, over the past few years, there has been a marked increase in gas exploration. A number of small independent oil and gas companies have entered the arena as exemplified by the 2004 gas lease sale by the State of Alaska. Table 10.3-1 summarizes gas production and remaining proven reserves by field as of January 1, 2004. Note that this Table includes 100,000 billion cubic feet for Happy Valley. This was the original reserves estimate for the field when Unocal first announced the discovery in November 2003. In 2005, once Unocal had drilled nine additional delineation wells and acquired 65 line miles of seismic data, the Alaska Oil and Gas Conservation Commission advised that the OGIP was estimated to be 93.7 billion cubic feet but recoverable reserves were only 38.6 billion cubic feet. Table 10.3-2 provides the latest data available from ADNR.

Table 10.3-1
Production data and reserve estimates by gas field in the Cook Inlet basin (AOGCC 2002a, 2003b, 2003c, 2003d, 2004 and ADNR 2003

Gas Field	Production, Non-Associated Gas, Discovery to January 01, 2004 (Bcf)	Production, Associated Gas Discovery to January 01/ 2004 (Bcf)	Proven Unproduced Reserves as of January 01, 2004 (Bcf)[5]	Estimated Ultimate Recovery (Bcf)
Albert Kaloa	0.119	0.000	0.000	0.119
Beaver Creek	170.150	2.020	71.110	243.280
Beluga River	847.163	0.000	312.908	1,160.071
Birch Hill	0.065	0.000	11.000	11.065
Cannery Lop	110.771	0.000	8.839	119.610
Falls Creek / Ninilchik[1]	3.064	0.000	96.936	100.000
Granite Point	0.800	125.099	11.164	137.063
Happy Valley	0.000	0.000	100.100[1]	100.000
Ivan River[2]	74.049	0.000	8.226	82.275
Kenai	2,245.566	0.000	99.599	2,345.525
Lewis River	10.882	0.000	See Ivan River	10.882+
Lone Creek	1.011	0.000	??	1.011+
McArthur River	966.750	253.938	173.353	1,395.041
Middle Ground Shoal	16.383	91.691	3.432	111.506
Moquawkie	0.988	0.000	20.000	20.988
Nicolai Creek	2.207	0.000	1.000	3.207
North Cook Inlet	1,621.587	0.000	571.971	2,193.558
North Fork	0.105	0.000	12.000	12.105
North Trading Bay	0.000	11.873	??	11.873+
Pretty Creek	8.273	0.000	See Ivan River	8.273+
Sterling	4.058	0.000	29.088	33.146
Stump Lake	5.643	0.000	See Ivan River	5.643+
Swanson River[4]	42.313	0.000	82.201	124.514
Trading Bay[3]	5.265	59.363	26.412	91.040
West Foreland	1.059	0.000	19.043	2`.`02
West Fork	4.212	0.000	4.000	8.212
West McArthur River	0.000	2.331	0.385	2.716
Wolf Lake	0.654	0.000	50.000	50.695
Totals	**6,143.581**	**564.315**	**1,713.583**	**8,403.479**

[1] Estimated recoverable reserves of 100 Bcf were assigned to the Ninilchik and Happy Valley discoveries [Marathon initially estimated recoverable reserves of 60 Bcf at Ninilchik and Unocal has placed initial estimates for Happy Valley at 75 to 100 Bcf (Petroleum News, 2003b), but Unocal puts the potential of the area from Ninilchik south to Anchor Point at 100 to 600 Bcf (Petroleum News, 2002)];

[2] DOG combined several smaller fields together when assigning future production; the unproduced reserves have been placed with the Ivan River field in this table;

[3] DOG reserve values have been used with the Trading Bay fields and future reserves put with the Trading Bay field;

[4]The to-date production figure represents the AOGCC value; the data presented by DOG shows much larger reserves (241 Bcf) but is difficult to rationalize;

[5]These values are derived from the DOG 2003 Annual Report for the major fields and the 1999 DOG Historical and Projected Oil and Gas Consumption Report for the smaller fields.

The seasonal peak gas demand of South-Central Alaska can be accommodated within a given supply regime through the use of some form of storage – typically underground storage and/or LNG. This technique is a fundamental aspect of gas distribution within the Lower 48 and much of the industrialized world. By way of example, on February 7, 1991 storage facilities supplied 57.5 percent of the gas send-out. Gas storage not only enables gas consumption to balance supply but also helps to mitigate short-term supply disruptions. In addition to this traditional use of gas storage, a more recent commercial use has been employed over the past few years. LNG and/or underground storage has been used to hedge against seasonal and/or monthly variations in gas prices. Typically underground storage utilizes depleted hydrocarbon reservoirs, aquifers or salt cavities. Experimentation with gas storage was first undertaken in 1915 in a gas field in Ontario. The first gas storage facility in a depleted reservoir was built in 1916 in a gas field in Zoar, near Buffalo, New York. Unocal has a gas storage facility in the Swanson River field. Unfortunately, this field is in the Kenai National Wildlife Refuge. Oil and gas activities within the Refuge are controlled by the Bureau of Land Management and Fish & Wildlife Service of the US Department of the Interior (the "BLM"). The BLM limits storage to gas produced within the Refuge. At present there is a debate regarding Unocal's request to store gas from production outside of the Reserve. Unocal states that a 16-inch diameter pipeline was constructed in1964 to import gas from other fields into the Swanson River field. This was used for field operations and as injection gas to maintain reservoir pressure an enhance oil recovery. Between 1964 and 1990, about 370 billion cubic feet of gas was imported, 40 billion cubic feet was used for field operations and 330 billion cubic feet were used for gas injection. Blowdown of the injected gas commenced in 1993 since which time, 230 billion cubic feet have been redelivered to the two industrial plants at Kenai.

The desirability of using other reservoirs, such as Beluga River, that supply the residential, commercial and power generation markets should be evaluated.

Table 10.3-2
Residual Proven Reserves Effective January 1, 2006

Historic and Projected Gas Production (Billion Cubic Feet per Year)

COOK INLET

	Beluga River[1]	McArthur River (TBU)[1]	North Cook Inlet[1]	Swanson River[1, 2]	Kenai/ Cannery Loop[1, 3]	Ninilchik/ Deep Creek[1]	All Other[1, 4]	Under-Development[5]	TOTAL NET
1958	-	-	-	0.0	-	-	-	-	0.0
1959	-	-	-	0.0	-	-	-	-	0.0
1960	-	-	-	-	-	-	-	-	-
1961	-	-	-	1.3	0.2	-	-	-	1.5
1962	-	-	-	1.8	1.5	-	0.0	-	3.3
1963	0.0	-	-	1.2	3.1	-	0.0	-	4.3
1964	0.1	-	-	1.6	4.5	-	0.1	-	6.2
1965	-	-	-	1.1	6.0	-	0.2	-	7.3

Historic and Projected Gas Production (Billion Cubic Feet per Year)

COOK INLET

	Beluga River[1]	McArthur River (TBU)[1]	North Cook Inlet[1]	Swanson River [1, 2]	Kenai/ Cannery Loop [1, 3]	Ninilchik/ Deep Creek[1]	All Other [1, 4]	Under-Develop ment [5]	TOTAL NET
1966	-	-	-	-	33.4	0.0	1.5	-	34.9
1967	0.2	0.2	-	-	39.6	-	9.0	-	49.1
1968	2.0	6.2	-	-	46.0	-	20.2	-	74.4
1969	3.0	14.2	7.9	-	59.3	-	22.3	-	106.8
1970	3.6	19.7	40.9	-	80.6	-	23.1	-	168.0
1971	4.1	19.3	45.0	-	72.2	-	22.4	-	163.0
1972	4.1	19.7	41.6	-	76.0	-	15.8	-	157.2
1973	4.9	19.1	42.7	-	71.3	-	13.1	-	151.2
1974	5.6	19.6	44.2	-	68.5	-	11.0	-	148.9
1975	7.0	21.5	45.6	-	77.2	-	10.6	-	161.9
1976	11.2	19.0	45.1	-	79.5	-	10.3	-	165.1
1977	13.4	19.7	47.2	-	81.9	-	10.8	-	172.9
1978	14.3	18.6	46.8	-	97.3	-	9.8	-	186.7
1979	17.0	16.6	49.4	-	97.0	-	8.6	-	188.7
1980	17.0	15.6	41.5	-	98.8	-	8.1	-	181.0
1981	17.2	15.2	49.5	-	105.8	-	7.7	-	195.4
1982	18.7	16.2	45.4	-	115.9	-	7.3	-	203.4
1983	18.1	14.4	47.9	2.2	113.0	-	15.2	-	210.7
1984	19.8	15.1	47.0	3.0	110.1	-	16.7	-	211.7
1985	22.6	10.7	45.8	3.1	115.8	-	18.9	-	216.9
1986	25.4	13.6	43.8	1.5	82.5	-	24.6	-	191.3
1987	24.0	13.3	42.9	(3.0)	90.0	-	22.1	-	189.3
1988	25.6	16.7	45.0	2.9	85.7	-	20.8	-	196.6
1989	30.1	31.0	45.3	(3.7)	77.0	-	18.7	-	198.4
1990	39.5	51.5	45.0	(1.6)	50.9	-	20.2	-	205.5
1991	38.5	61.2	44.7	(0.1)	37.9	-	20.9	-	203.1
1992	36.5	70.1	44.4	(0.2)	34.8	-	18.8	-	204.5

Historic and Projected Gas Production (Billion Cubic Feet per Year)

COOK INLET

	Beluga River[1]	McArthur River (TBU)[1]	North Cook Inlet[1]	Swanson River [1, 2]	Kenai/ Cannery Loop [1, 3]	Ninilchik/ Deep Creek[1]	All Other [1, 4]	Under-Development [5]	TOTAL NET
1993	31.7	62.5	45.5	4.6	33.3	-	22.7	-	200.5
1994	34.2	50.0	52.7	27.3	25.2	-	24.6	-	214.0
1995	35.6	54.9	53.5	28.7	22.0	-	19.6	-	214.5
1996	36.9	67.3	56.0	33.3	15.4	-	14.1	-	223.0
1997	35.0	66.8	52.5	28.7	15.8	-	15.9	-	214.7
1998	33.4	73.8	54.0	25.8	12.8	-	15.2	-	215.0
1999	36.0	69.0	51.6	29.8	12.8	-	13.4	-	212.6
2000	38.7	65.0	52.8	29.7	17.1	-	12.4	-	215.8
2001	41.8	62.3	55.5	22.0	24.1	-	13.9	-	219.7
2002	44.0	51.5	54.6	12.8	27.2	-	19.9	0.0	210.0
2003	56.3	39.2	47.9	6.6	34.7	3.0	17.4	3.0	208.2
2004	57.6	34.4	41.0	5.8	37.9	12.7	18.7	-	208.1
2005	55.9	30.8	45.6	3.1	36.8	18.0	18.7	-	208.8
2006	57.1	26.9	42.7	2.3	37.7	17.8	20.6	1.1	206.2
2007	57.0	19.6	37.1	1.2	31.1	12.3	14.5	16.8	189.6
2008	57.0	15.0	32.3	0.5	25.4	9.2	10.8	20.9	171.0
2009	49.1	11.5	28.0	1.5	20.7	6.9	8.2	26.1	151.8
2010	46.3	8.8	24.3	1.1	16.9	5.2	6.5	24.6	133.7
2011	39.7	6.8	21.1	0.8	13.9	4.0	5.2	23.5	114.9
2012	34.1	5.3	18.4	0.6	11.4	3.1	4.3	22.9	100.1
2013	29.2	4.1	15.9	0.4	9.3	2.4	3.6	21.1	86.0
2014	25.0	3.2	13.9	0.3	7.6	1.9	3.0	18.0	72.9
2015	21.5	2.5	12.0	0.2	6.3	1.5	2.4	15.5	62.0
2016	18.5	1.9	10.5	0.2	5.2	1.2	2.0	13.5	53.0
2017	15.8	1.5	9.1	0.1	4.3	1.0	1.7	11.2	44.6
2018	13.5	1.1	7.9	0.1	3.5	0.9	1.5	9.2	37.7
2019	11.6	0.8	6.9	0.1	2.9	0.7	1.3	7.7	32.0

Historic and Projected Gas Production (Billion Cubic Feet per Year)

COOK INLET

	Beluga River[1]	McArthur River (TBU)[1]	North Cook Inlet[1]	Swanson River [1, 2]	Kenai/ Cannery Loop [1, 3]	Ninilchik/ Deep Creek[1]	All Other [1, 4]	Under-Development [5]	TOTAL NET
2020	10.0	0.6	6.0	0.0	2.4	0.6	1.1	6.4	27.1
2021	8.5	0.4	5.2	0.0	2.0	0.6	1.0	5.4	23.1
2022	7.3	0.3	4.5	-	1.6	0.5	0.6	4.5	19.4
2023	6.3	-	3.9	-	1.3	0.4	0.6	4.1	16.6
2024	5.4	-	3.4	-	1.1	0.4	0.5	3.4	14.2
2025	4.6	-	2.9	-	0.9	0.3	0.5	2.8	12.1
2026	4.0	-	2.6	-	0.7	0.3	0.1	1.6	9.2
2027	3.4	-	2.2	-	0.6	0.3	0.1	1.3	7.9
2028	2.9	-	1.9	-	0.5	0.3	0.0	1.1	6.8
2029	2.5	-	1.7	-	0.4	0.2	0.0	0.9	5.8
2030	2.1	-	1.5	-	0.3	0.2	0.0	0.7	4.9
2031	1.8	-	1.3	-	0.3	0.2	0.0	0.6	4.2
2032	1.6	-	1.1	-	0.2	0.2	0.0	0.4	3.5
2033	1.3	-	1.0	-	0.2	0.2	0.0	0.3	2.9
2034	1.2	-	0.8	-	0.1	0.2	0.0	0.2	2.5
2035	1.0	-	0.7	-	0.1	0.2	-	0.2	2.2
Cumulative Remaining	539.4	110.2	320.8	9.3	208.9	73.4	90.4	266.2	1,618.4

Notes:

1 Production forecasts 2006-35 based on decline and material balance analysis of proved, developed reserves.

2 Net gas injections reported for Swanson River 1966-82.

3 Includes Kenai pools: Sterling #3, 4, 5.1, 5.2, 6, and Upper Tyonek-Beluga, Tyonek, and Beluga Undefined; plus all Cannery Loop pools.

4 All Other includes proved developed producing reserves of Albert Kaloa, Beaver Creek, Granite Point, Ivan River, Lewis River, Pretty Creek, Stump Lake, Lone Creek, MGS, Moquawkie, Nicolai Creek, North Fork, North Trading Bay, Redoubt, Sterling, Three-Mile Creek, Trading Bay, West Foreland, West Fork, West McArtur River and Wolf Lake.

5 Includes DNR estimates of non-producing, probable reserves based primarily on gas prospectivity in the Kasilof, Nikolaevsk, and North Fork exploration areas. Also includes probable reserves estimates for the developed-producing fields: Deep Creek, McArthur River, Ninilchik, NCIU, and Three-Mile Creek.
6 Total does not include Tyonek Deep project.

Source of Historic Data 1985-2005: Alaska Oil and Gas Conservation Commission, "Alaska Production Summary by Field and Pool", Monthly Reports.

10.4 THE FUTURE OF THE KENAI LNG PLANT

At the request of ANGDA, Stone & Webster Consultants herein has evaluated several options regarding the commercial future of the Kenai LNG plant. The first of these options is the continued operation of the facilities at a declining LNG production rate, as Cook Inlet gas supplies are diverted to residential and light commercial use. A second option is an expansion of the Kenai LNG plant, which in reality is a replacement of the current gas processing facilities with a new liquefaction plant with essentially double the capacity of the existing plant. The viability of this option requires substantial new gas reserves in the Cook Inlet or the installation of a new 500 MMscfd Spur Line from Fairbanks to Anchorage that is tied into the main North Slope ANGP to the Lower 48 States. A third option considered is the conversion of the existing plant to a LNG peak shaving plant, which would enable the winter peak demand to be accommodated. This relies on additional gas discoveries and production from the Cook Inlet gas fields to support power generation and residential and commercial natural gas consumption through 2025. Finally, the fourth option considered is the conversion of the new plant to a LNG receiving and re-vaporization terminal, which assumes Cook Inlet gas production is initially supplemented and, in due course, replaced by LNG imports from abroad.

The commercial future of the Kenai plant is not obvious. From the visit to the plant, Stone & Webster Consultants concludes that the plant and supporting infrastructure is good condition for its age. In part this is due to the relatively benign environment, low temperature and low salinity. There is little evidence of external corrosion. The plant has not been subject to a significant number of thermal cycles and the problems that this can induce into metallurgy. Rotating equipment has a significant run-life, but can most probably continue to operate reliably for another five years. Operation beyond March 2009 would require a renewed export license and extensions to the current LNG sales contracts or some form of short term sales contract with other parties. Taking into account the time to secure both of these, the decision would need to be taken in late 2006 or early 2007. Disposition of LNG into the USA would require a waiver of the requirements of the Jones Act. Specifically, the two LNG carriers were constructed in Japan, not the USA. In the event that additional reserves are located in the Cook Inlet, the decision could be taken to pursue life extension of the existing plant or expansion of the plant. Alternatively, if the Spur Line were constructed from ANGP to Palmer and on to Kenai, then that gas supply could warrant continued operation of the plant. We would expect a minimum operating life of 15 years to justify an expansion.

Technically, the plant could be converted to some form of LNG peak shaving facility. However, there is no obvious economic benefit to this when compared to using depleted reservoirs within the Cook Inlet Basin to store gas.

Conversion of the facility to a LNG receiving terminal would appear to provide a solution to the issue of gas supply to South-Central Alaska in the event that North Slope gas is exported to the Lower 48 through one of the northern routes that makes the Spur Line impracticable. Such a facility could utilize the existing LNG carriers for supply, the existing LNG tanks for storage and the existing infrastructure. Vaporizers and send-out facilities would be required. The economic return on such a plant would determine the cost of gas to South-Central Alaska. Since the internal rate of return required by oil and gas majors is relatively high, it may make economic sense for the local utilities to combine together and purchase and operate the facility.

10.5 CONCLUSION

The natural economic life of the Kenai LNG plant is nearing its end. Provided that an export license can be obtained, and additional reserves obtained to justify continued operation, then the plant could operate through 2011 and perhaps beyond that date albeit with decreasing availability/reliability. This mode of operation could potentially support spot sales of LNG.

Robust and continuous operation of the Kenai LNG plant beyond 2011 will require significant investment. This investment will in turn require a guaranteed source of gas for at least a 15-year period. As a minimum, major elements of the plant would be replaced on a like for like basis. More likely, the plant would be upgraded and optimized, possibly increasing the capacity of the plant to three million metric tonnes per year of LNG. In this instance, additional investment would be required in the LNG carrier fleet too.

Unless a timely decision is made to construct the ANGP and associated Spur Line, such that gas can be delivered to the South-Central Alaska area by 2014, then the area will be deficient in gas. In this instance, the Kenai LNG plant could be converted to use as a LNG receiving and regasification terminal at the end of its natural life as a baseload LNG plant. This change of use may be associated with a change of ownership. It may be appropriate for one or more of the local utilities to purchase the plant, undertake the conversion and operate the plant as part of an integrated gas grid serving South-Central Alaska.

APPENDIX A: FURTHER READING

1. South-Central Alaska Natural Gas Study
2. Transport of North Slope Natural Gas to Tidewater, April 2005, Michael Baker

Unocal	**www.unocal.com**
Chevron	**www.chevron.com**
Marathon	**www.marathon.com**
ConocoPhillips	**www.conocophillips.com**
Northstar Energy	**www.nothstarenergyinc.com**
Forest Oil	**www.forestoil.com**
Aurora	**www.aurorapower.com**
XTO Energy	**www.crosstimbers.com**
Chugach	**www.chugachelectris.com**
Alaska Municipal Power & Light	**www.mlandp.com**
ENSTAR	**www.enstarnaturalgas.com**
Agrium	**www.agrium.com**

Natural Gas

Natural Gas is a naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in porous geologic formations. The primary component is methane. It is derived from the decomposition of organic matter.

British Thermal Unit

The British Thermal Unit ("Btu") is the amount of heat required to change the temperature of one pound of water by one degree Fahrenheit.

Uses

Natural gas is used as an energy source to heat and/or cool residential properties, as a fuel in the generation of electric power and as a feedstock for many petrochemicals.

Further Data

A comprehensive primer of natural gas can be found on http://www.naturalgas.org

Liquefied Natural Gas

Liquefied Natural Gas ("LNG") is natural gas that has been cooled to a temperature of approximately -161° Centigrade (-260° Fahrenheit) at approximately atmospheric pressure. It is a colorless, non-toxic, non-corrosive and odorless liquid with a density that is less than half that of water. The change from the gaseous to liquid state results in a volume reduction by a factor of 610. This reduction in volume facilitates the transportation of natural gas to remote users. LNG typically contains at least 85 percent methane, but this can be as high as 98 percent. The remainder of the composition is ethane, propane, butane and small quantities of nitrogen. .

LNG Carrier

LNG is transported in specially-built double-hulled ships, LNG carriers. These contain LNG in insulated tanks. At the LNG terminal, the LNG is transferred to LNG tanks from where it is piped to vaporizers that gasify the LNG before it enters the receiver's gas transmission and distribution system.

LNG Baseload Plant

A facility that is designed to receive natural gas, remove impurities and produce LNG for sale to a third party. Current LNG Baseload Plants have single train capacities of between three and eight million metric tonnes per annum.

Peak Shaving LNG Facility

A peak shaving LNG facility stories and vaporizes LNG on a short-term and intermittent basis to meet short-term peak gas demand. Inland facilities also have small-scale LNG production capability.

LNG Receiving and Regasification Terminal

A LNG receiving and regasification terminal is a coastal plant that receives LNG produced in baseload LNG plants and transported in LNG carriers. The LNG is transferred to LNG storage tanks from where it is pumped through vaporizers to produce clean, sweet natural gas.

Further Data

An informative videos regarding the properties and behavior of LNG can be found on the following web sites: http://lnglicensing.conocophillips.com and http://www.bplng.com/environment/video.asp.

Attached hereto is a primer on LNG, DOE/FE-0489 published by the US Department of Energy: http://www.fossil.energy.gov.

Liquefied Natural Gas:

Understanding the Basic Facts

Liquefied Natural Gas:

Understanding the

> "I strongly support developing new LNG capacity in the United States."
>
> *–President George W. Bush*

About This Report

This report was prepared by the U.S. Department of Energy (DOE) in collaboration with the National Association of Regulatory Utility Commissioners (NARUC). DOE's Office of Fossil Energy supports technology research and policy options to ensure clean, reliable, and affordable supplies of oil and natural gas for American consumers, working closely with the National Energy Technology Laboratory, which is the Department's lead center for the research and development of advanced fossil energy technologies. NARUC, a nonprofit organization composed of governmental agencies engaged in the regulation of telecommunications, energy, and water utilities and carriers in the 50 states, the District of Columbia, Puerto Rico, and the Virgin Islands, serves the public interest by improving the quality and effectiveness of utility regulation.

Design and editorial support: Akoya

Select photos courtesy of: Anadarko Petroleum Company; Atlantic LNG Company of Trinidad and Tobago; British Petroleum; Chevron Texaco; ConocoPhillips; Dominion Cove Point LNG, LP; Excelerate Energy; HOEGH LNG; Pine Needle LNG, LLC NC; Texaco Production Operations; Tractebel LNG North America; Trunkline LNG

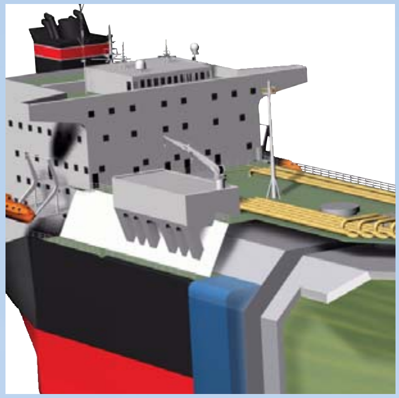
Basic Facts

6

Current Status of U.S. LNG Imports

The United States currently has six LNG terminals—four on the mainland, one in the offshore Gulf of Mexico, and one in Puerto Rico—that receive, store, and regasify LNG. Some economists call for the development of more import capacity to enable the United States to participate fully in world LNG markets.

Expanded LNG imports would likely help to dampen natural gas price volatility in the United States, particularly during peak periods of demand. Such expanded imports would also support U.S. economic growth.



8

Components of the LNG Value Chain

If the United States is to increase LNG imports, significant capital investment will be necessary by energy firms across the entire LNG "value chain," which spans natural gas production, liquefaction capacity, transport shipping, storage, and regasification.

Over the past two decades, technology improvements have been key to a substantial increase in liquefaction efficiency and decrease in LNG costs.

16

Informed Decision Making

For more than 40 years, the safety record of the global LNG industry has been excellent, due to attention to detail in engineering, construction, and operations. More than 30 companies have recently proposed new LNG terminals in North America, along the U.S. coastline or offshore. Each proposal is rigorously evaluated before an LNG terminal can be constructed or expanded.

Americans face the challenge of making sound and timely decisions about LNG infrastructure to assure an abundant supply of natural gas for homes, businesses, industry, and power generators, in the near and long term.

Growing Demand for

Natural Gas

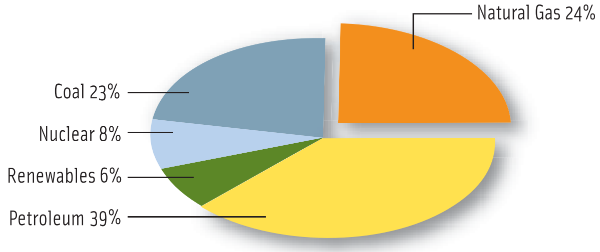
The United States relies on clean-burning natural gas for almost one quarter of all energy used. Natural gas has proven to be a reliable and efficient energy source that burns much cleaner than other fossil fuels. In the last 10 years, the United States produced between 85 and 90 percent of the natural gas it consumed.[1] Most of the balance was imported by pipeline from Canada.

Annual U.S. natural gas consumption is projected to rise from 22.1 trillion cubic feet (Tcf) in 2004 to 30.7 Tcf in 2025.[2] Reasons for the increase include:

- Utilities realize advantages by using natural gas-fired generators to create electricity (lower capital costs, higher fuel efficiency, shorter construction lead times, and lower emissions).
- The residential sector benefits from the higher fuel efficiency and lower emissions of gas appliances.
- The industrial sector relies on natural gas as a feedstock or fuel for manufacturing many of the products we rely on today, including pulp and paper, metals (for computers, automobiles, and telecommunications), chemicals, fertilizers, fabrics, pharmaceuticals, and plastics.
- The transportation sector is beginning to see natural gas as a clean and readily available alternative to other fossil fuels.

FIGURE 1

Natural gas accounted for almost one-quarter of all energy used in the United States from 1998-2003.



Source: Energy Information Administration, *Annual Energy Outlook 2005*

While U.S. demand is rising, production of natural gas in major mature provinces, including North America, is beginning to decline. Lack of a steady supply increases the potential for higher energy prices and price volatility, which affect the profitability and productivity of industry and may spur certain gas-intensive industries to relocate to parts of the world where natural gas is less expensive. This, in turn, could impact jobs, energy bills, and the prices paid for consumer goods.

One way to help meet rising demand would be to increase imports of natural gas from outside North America. Net imports of natural gas are projected to supply 19 percent of total U.S. consumption in 2010 (4.9 Tcf) and 28 percent in 2025 (8.7 Tcf).[3] This natural gas will be transported via ship in the form of liquefied natural gas (LNG). Net imports of LNG are expected to increase from 0.6 Tcf in 2004[4] to more than 6 Tcf in 2025—at that point satisfying almost 21 percent of total U.S. natural gas demand.[5]

Discussions of the benefits and risks of expanding LNG imports will be central to U.S. energy supply decisions in the years ahead. A key consideration is the potential of LNG imports to ensure that adequate and reliable supplies of natural gas are available to support U.S. economic growth.

Numerous recent studies have underscored the importance of LNG in the nation's energy future:

- A 2003 study by the National Petroleum Council conducted at the request of the Secretary of Energy found several keys to ensuring a reliable, reasonably priced natural gas supply to meet future U.S. demand—including increased imports of LNG.[6]
- A 2004 Energy Information Administration (EIA) study, *Analysis of Restricted Natural Gas Supply Cases*, included a forecast scenario based on a "restricted" expansion of U.S. LNG import terminals. The results showed an increase in natural gas prices, dampening consumption and economic growth.
- A 2004 study by the Manufacturers Alliance outlined the critical role of natural gas in manufacturing and the potential contribution of LNG to improve U.S. industrial competitiveness in the global marketplace.[7]

Meeting Future Demand

The United States will not be the only nation competing for natural gas imports in the future. In 2001 the worldwide community consumed about 90 trillion cubic feet (Tcf) of natural gas. Consumption of natural gas worldwide is projected to increase by an average of 2.2 percent annually or 70 percent overall from 2001 to 2025, to about 151 trillion cubic feet.[8]

Fortunately, global natural gas resources are vast—estimated at about 6,079 Tcf in recoverable gas as of 2004, roughly 60 times the recent annual volume consumed.[9] In total, worldwide natural gas resources are estimated at more than 15,000 Tcf, including gas that has yet to be discovered.[10]

The international LNG business connects natural gas that is "stranded"—far from any market—with the people, factories, and power plants that require the energy. It becomes necessary to transport natural gas as LNG because the distribution of the world's supply of natural gas is not consistent with patterns of demand.

Russia, Iran, and Qatar hold 58.4 percent of the world's natural gas reserves, yet consume only about 19.4 percent of worldwide natural gas. Such countries tend to "monetize" their gas resource—converting it into a salable product. LNG makes this possible.

The world's major LNG-exporting countries hold about 25 percent of total natural gas reserves. Two countries with significant reserves (Russia and Norway) are currently building their first liquefaction facilities. At least seven more are considering the investment to become LNG exporters in the near future.

In some cases, conversion to LNG makes use of natural gas that would once have been lost. For example, Nigeria depends on its petroleum exports as a primary source of revenue. In the process of oil production, natural gas was flared—a wasteful practice that adds carbon dioxide to the atmosphere. Converting this natural gas to LNG provides both economic and environmental benefits.

1 Energy Information Administration (EIA), *Annual Energy Review 2003*, September 2004.

2 EIA, *Annual Energy Outlook 2005*.

3 EIA, *Annual Energy Outlook 2005*.

4 DOE, *Natural Gas Imports and Exports*, Fourth Quarter 2004.

5 EIA, *Annual Energy Outlook 2005*.

6 National Petroleum Council, *Balancing Natural Gas Policy–Fueling the Demands of a Growing Economy*, September 2003.

7 Norman, Donald A., *Liquefied Natural Gas and the Future of Manufacturing*, Manufacturers Alliance, September 2004.

8 EIA, *International Energy Outlook 2004*.

9 EIA, *International Energy Annual 2003*, released May 2005.

10 U.S. Geological Survey, *World Petroleum Assessment 2000*.

FIGURE 2

LNG is mostly methane plus a few percent ethane, even less propane and butane, and trace amounts of nitrogen.

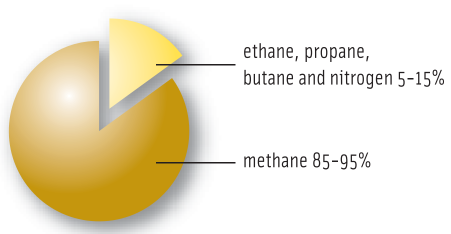
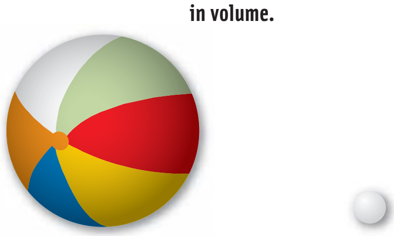


FIGURE 3

When natural gas is liquefied, it shrinks more than 600 times in volume.



When liquefied, natural gas that would fill a beach ball…

…becomes LNG that can fit inside a ping-pong ball.

LNG…A SAFE FUEL IN A SMALL PACKAGE

Natural gas consists almost entirely of methane (CH_4), the simplest hydrocarbon compound. Typically, LNG is 85 to 95-plus percent methane, along with a few percent ethane, even less propane and butane, and trace amounts of nitrogen (Figure 2). The exact composition of natural gas (and the LNG formed from it) varies according to its source and processing history. And, like methane, LNG is odorless, colorless, noncorrosive, and nontoxic.

Natural gas is condensed to a liquid by cooling it to about -260°F (-162°C). This process reduces its volume by a factor of more than 600—similar to reducing the natural gas filling a beach ball into liquid filling a ping-pong ball (Figure 3). As a result, just one shipload of LNG can provide nearly 5 percent (roughly 3 billion cubic feet) of the U.S. average daily demand for natural gas, or enough energy to heat more than 43,000 homes for an entire year![11]

LNG is transported by ship to terminals in the United States, then stored at atmospheric pressure in super-insulated tanks. From storage, LNG is converted back into gas and fed into the natural gas pipeline system. LNG is also transported by truck to satellite storage sites for use during peak periods of natural gas demand—in the coldest weather for heating and in hot weather for fueling electric power generators, which in turn run air conditioners.

11 See LNG conversion tables, page 9.

Emergence of the

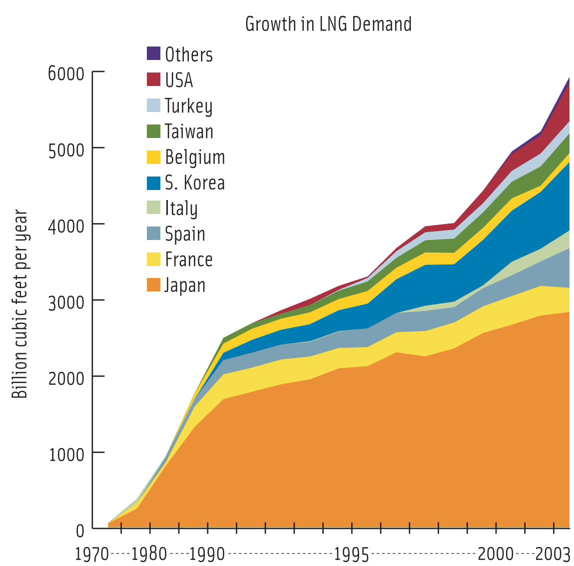
Global LNG Market

Efforts to liquefy natural gas for storage began in the early 1900s, but it wasn't until 1959 that the world's first LNG ship carried cargoes from Louisiana to the United Kingdom, proving the feasibility of trans-oceanic LNG transport. Five years later, the United Kingdom began importing Algerian LNG, making the Algerian state-owned oil and gas company, Sonatrach, the world's first major LNG exporter. The United Kingdom continued to import LNG until 1990, when British North Sea gas became a less expensive alternative.

Japan first imported LNG from Alaska in 1969 and moved to the forefront of the international LNG trade in the 1970s and 1980s with a heavy expansion of LNG imports. These imports into Japan helped to fuel natural-gas-fired power generation to reduce pollution and relieved pressure from the oil embargo of 1973. Japan currently imports more than 95 percent of its natural gas and, as shown in Figure 4, serves as the destination for about half the LNG exported worldwide.

FIGURE 4

Japan has been the major client of the LNG business for 30 years, but the size of the market and the number of importers are growing steadily.



Source: Cedigaz (1970-1992); EIA (1993-2003)

The United States first imported LNG from Algeria during the 1970s, before regulatory reform and rising prices led to rapid growth of the domestic natural gas supply. The resulting supply-demand imbalance (known as the "gas bubble" of the early 1980s) led to reduced LNG imports during the late 1980s and eventually to the mothballing of two LNG import facilities. Then, in the 1990s, natural gas demand grew rapidly, and the prospect of supply shortfalls led to a dramatic increase in U.S. LNG deliveries. In 1999 a liquefaction plant became operational in Trinidad and Tobago, supplying LNG primarily to the United States.

Current LNG Market Structure

International trade in LNG centers on two geographic regions (see Figure 5):[12]

- The Atlantic Basin, involving trade in Europe, northern and western Africa, and the U.S. Eastern and Gulf coasts.
- The Asia/Pacific Basin, involving trade in South Asia, India, Russia, and Alaska.

In addition, Middle Eastern LNG-exporting countries between these regions supply Asian customers primarily, although some cargoes are shipped to Europe and the United States.

LNG prices are generally higher in the Asia/Pacific Basin than in the Atlantic Basin. However, in the United States the price of LNG can rise with peak seasonal demand to attract short-term delivery of LNG cargoes.

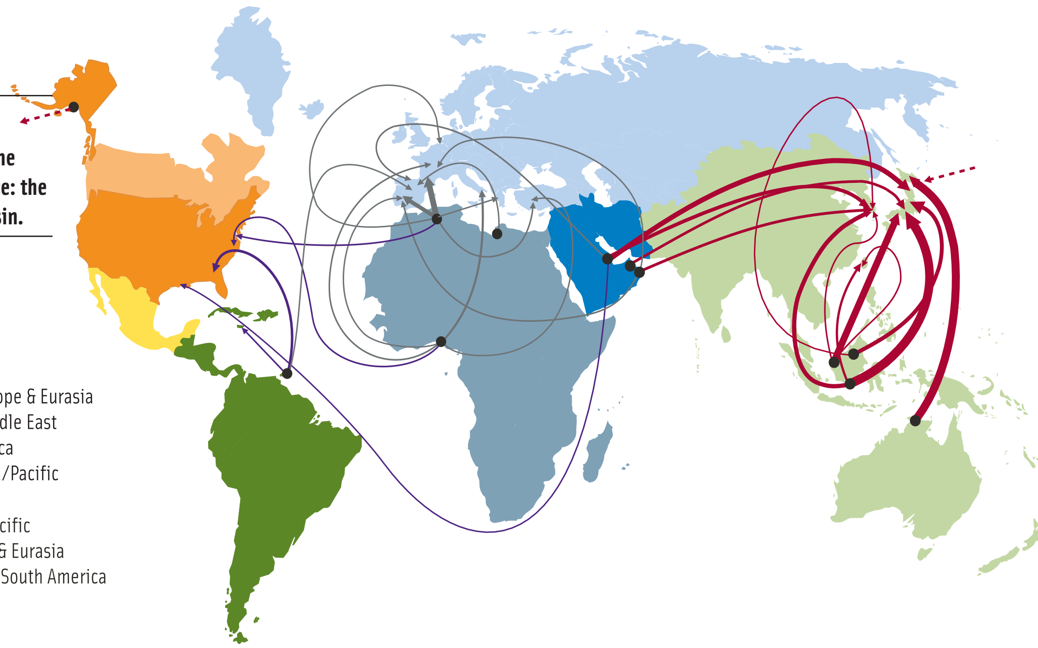
LNG importers. Worldwide in 2003 a total of 13 countries imported LNG. Three countries in the Asia/Pacific Basin—Japan, South Korea, and Taiwan—accounted for 67 percent of global LNG imports, while Atlantic Basin LNG importers took delivery of the remaining 33 percent.[13]

Japan remains the world's largest LNG consumer, although its share of global LNG trade has fallen slightly over the past decade as the global market has grown. Japan's largest LNG suppliers are Indonesia and Malaysia, with substantial volumes also imported from Qatar, the United Arab Emirates, Australia, Oman, and Brunei Darussalam. Early in 2004 India received its first shipment of LNG from Qatar at the newly completed facility at Dahej in Gujarat.

FIGURE 5

LNG trading can be categorized by the geographic region in which it takes place: the Atlantic Basin or the Asia/Pacific Basin.

Source: Energy Information Administration and British Petroleum



Imports by Atlantic Basin countries are expected to grow as many expand storage and regasification terminal capacity. France, Europe's largest LNG importer, plans two new terminals for receipt of gas from Qatar and Egypt. Spain's LNG imports, roughly half from Algeria, increased by 21 percent in 2003. All Spanish regasification terminals are being expanded, with several new terminals starting up by 2007. Italy and Turkey receive LNG from Nigeria and Algeria. Belgium has one regasification terminal and receives most of its LNG from Algeria. In 2003 the Dominican Republic and Portugal began operating regasification terminals. Other potential Atlantic Basin LNG importers include the Bahamas, Canada, Jamaica, Mexico, the Netherlands, and the United Kingdom.

LNG exporters. Asia/Pacific Basin LNG producers accounted for nearly half of total world LNG exports in 2003 while Atlantic Basin LNG producers accounted for about 32 percent. Liquefaction capacity in both regions is increasing steadily.[14]

Indonesia is the world's largest LNG producer and exporter, accounting for about 21 percent of the world's total LNG exports. The majority of Indonesia's LNG is imported by Japan, with smaller volumes going to Taiwan and South Korea. Malaysia, the world's third-largest LNG exporter, ships primarily to Japan with smaller volumes to Taiwan and South Korea. Australia exports LNG from the Northwest Shelf, primarily to supply Japanese utilities. About 90 percent of Brunei Darussalam output goes to Japanese customers. The only liquefaction facility in the United States was constructed in Kenai, Alaska, in 1969. This facility, owned by ConocoPhillips and Marathon Oil, has exported LNG to Japan for more than 30 years.

Russia is becoming the newest Asia/Pacific Basin exporter. Its first LNG plant is under construction on Sakhalin Island off the country's east coast. This large facility is scheduled to begin operation in 2008.

Planned expansions of existing plants could dramatically increase Atlantic Basin liquefaction capacity by 2007. Algeria, the world's second-largest LNG exporter, serves mainly Europe (France, Belgium, Spain, and Turkey) and the United States via Sonatrach's four liquefaction complexes. Nigeria exports mainly to Turkey, Italy, France, Portugal, and Spain but also has delivered cargos under short-term contracts to the United States. Trinidad and Tobago exports LNG to the United States, Puerto Rico, Spain, and the Dominican Republic. An Egyptian facility exported its first cargo in 2005 and is expected to supply France, Italy, and the United States. Beginning in 2006 Norway plans to export LNG from Melkøye Island to markets in Spain, France, and the United States.

12 EIA, *The Global Liquefied Natural Gas Market: Status and Outlook*, December 2003, and other sources.

13 EIA, World LNG Imports by Origin, 2003.

14 EIA, World LNG Imports by Origin, 2003.

Current Status of U.S.

LNG Imports

In 2003 the United States imported 506.5 Bcf of LNG from a variety of exporting countries. Imports in 2004 increased by 29 percent, reaching 652 Bcf.

LNG arriving in the continental United States enters through one of five LNG receiving and regasification terminals located along the Atlantic and Gulf coasts. While these facilities have a combined peak capacity of more than 1.3 Tcf per year, imports in 2004 totaled only a little more than 0.65 Tcf.* However, future demand for LNG will outgrow current and future capacity at the five terminals. By 2008 these terminals should reach a peak capacity of 2.1 Tcf and then level off. On the other hand, EIA projects LNG demand of 6.4 Tcf to meet U.S. natural gas needs by 2025. Clearly, the nation will need to rely on additional import terminals or face a serious natural gas shortfall in coming decades. LNG receiving terminals are located in:

Everett, Massachusetts. Owned and operated by Tractebel LNG North America, the facility began operations in 1971 and now meets 15 to 20 percent of New England's annual gas demand. A recent expansion raised baseload capacity to 265 Bcf per year.**

Cove Point, Maryland. Operated by Dominion Cove Point LNG, the Cove Point terminal began operation in 1978, was mothballed for two decades, and reopened in July 2003. A proposed expansion project will increase baseload capacity from the current 365 Bcf per year to about 657 Bcf by 2008.

Elba Island, Georgia. Owned by El Paso Corporation and the smallest of the continental U.S. terminals, the Elba Island facility began operation in 1978. Like Cove Point, Elba was mothballed during the 1980s and reactivated in 2001. Its current baseload capacity of 161 Bcf per year will be expanded to 292 Bcf per year by 2008.

Lake Charles, Louisiana. Operated by Panhandle Energy/Trunkline LNG, the Lake Charles terminal was completed in July 1981. A two-phase expansion will raise capacity from the current baseload 230 Bcf per year to about 657 Bcf in 2007.[15]

Gulf Gateway, Gulf of Mexico Offshore. Owned by Excelerate Energy, the sub-sea Gulf Gateway Energy Bridge is 116 miles off the Louisiana coast and began operations in March 2005 as the world's first offshore receiving port. The facility has a baseload capacity of 183 Bcf per year and uses converted LNG carriers to regasify LNG through deck-mounted vaporizers.

A sixth terminal, the EcoEléctrica regasification facility (capacity of 33.9 Bcf per year) in the U.S. Commonwealth of Puerto Rico, began importing LNG in 2000 to serve a 540-megawatt natural gas-fired power plant that accounts for about 20 percent of the electricity generated on the island.

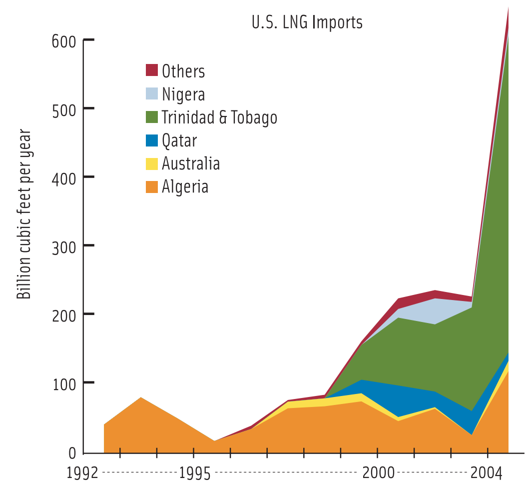
* Sustainable sendout ("baseload") regasification capacity will increase from more than 1.0 Tcf in 2004 to 1.8 Tcf in 2008.

** Does not include about 36 Bcf per year trucked to various New England destinations.

15 Capacities from EIA (*LNG Markets and Uses: June 2004 Update*), FERC, facility websites, and other sources.

FIGURE 6

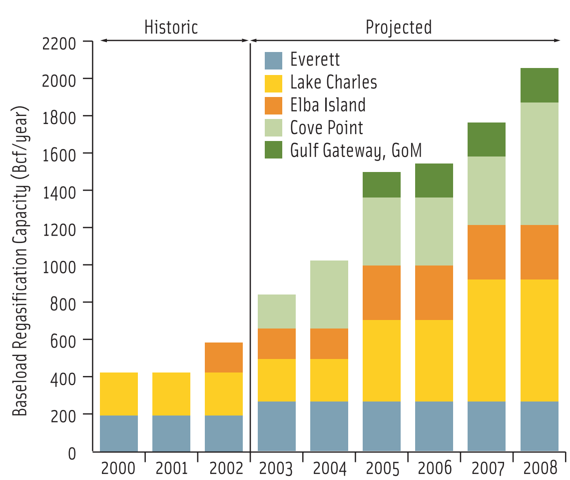
Most U.S. LNG imports come from Trinidad and Tobago. The balance originates from a mix of Middle Eastern, African, and Asian suppliers.



Source: DOE FE-LNG Imports by Country of Origin, 2004

FIGURE 7

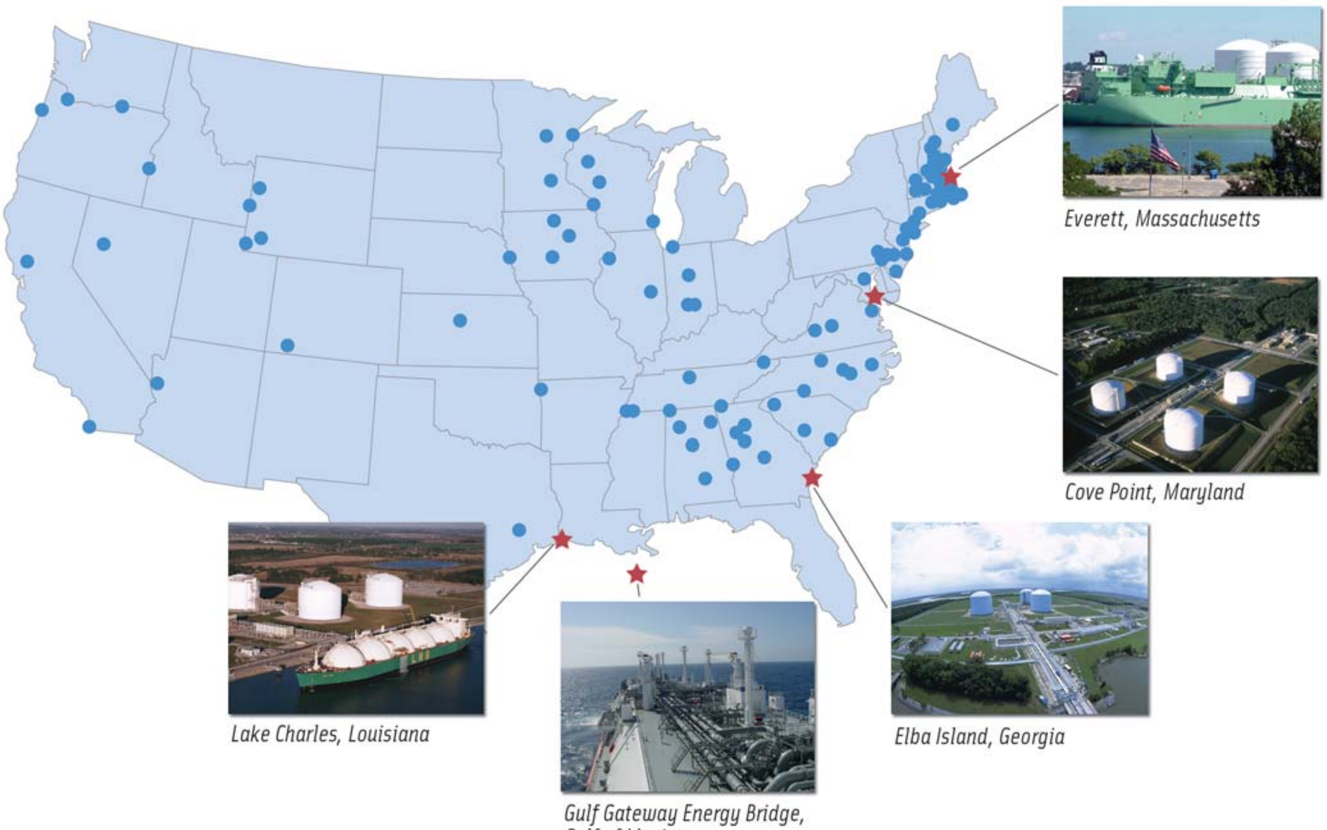
Even with planned expansions, the capacity of existing U.S. LNG terminals will meet less than half of the forecasted 6,400 Bcf LNG demand in 2025.



*Gulf Gateway began was commissioned for operation in April of 2005. 2005 data is pro-rated for 9 months.
Source: Energy Information Administration, FERC, and other sources

FIGURE 8

In addition to onshore and offshore import terminals along the nation's coastline, more than 100 satellite facilities located in the United States store LNG and supply natural gas to rural areas, as well as serving as cost-effective peak shavers at times of high usage.



Source: EIA, *U.S. LNG Markets and Uses: June 2004 Update*

The Pine Needle, North Carolina peak-shaving facility, one of the largest in the nation, has a storage capacity of 4 Bcf. A sendout capacity of .4 Bcfd empties the tanks in 10 days of peak usage.

LNG STORAGE AND "PEAK SHAVING"

Consumer demand for natural gas normally rises and falls within a certain range easily handled by gas utilities and the transmission pipelines that supply them. However, during extremely cold spells or other events or emergencies, demand for natural gas may "peak" sharply above normal baseline demand. Utilities need a reliable supply of gas that can be quickly delivered into the distribution system to flatten out or "shave" peaks in demand. The United States currently has more than 100 active peak-shaving plants and other satellite facilities, most of which were built between 1965 and 1975. The majority of these facilities are found in the Northeast, Upper Midwest, and Southeast. Approximately 55 local utilities own and operate small-scale LNG plants. At such facilities, natural gas is diverted from a pipeline, liquefied, and stored until needed. In some instances the LNG is trucked to satellite storage tanks. LNG is also trucked to satellite storage tanks from the LNG import terminal in Everett, Massachusetts. When demand spikes, the stored LNG is regasified and fed into the distribution system. The total annual LNG turnover in peak-shaving storage ranges between 35 and 68 Bcf per year, compared to the 652 Bcf of LNG imported during 2004. In addition, a small, relatively underdeveloped niche market (about .1 Bcf) uses LNG as a vehicle fuel or as an alternative to propane fuel at isolated industrial facilities.

Components of the LNG

Value Chain

The global LNG business has been described as a "value chain" containing four components: (1) Exploration and Production, (2) Liquefaction, (3) Shipping, and (4) Storage and Regasification, providing natural gas for delivery to several categories of "end user." To attract investors to an LNG project, the price of a unit volume of gas delivered into a pipeline must at least equal the combined costs of producing, liquefying, transporting, storing, and revaporizing the gas, plus the costs of the capital needed to build necessary infrastructure—and a reasonable return to investors. The largest component of the total cost of the LNG value chain is usually the liquefaction plant, while the production, shipping, and regasification components account for nearly equal portions of the remainder.[16]

Technology improvements have reduced costs in all components of the LNG value chain during the last 20 years. Several factors—improved efficiency through design innovations, economies of scale through larger train sizes,[17] and competition among manufacturers—have led to a drop in capital costs for liquefaction plants from $600 per ton of capacity in the late 1980s to about $200 per ton in 2001.[18] Costs have dropped for expansions to existing plants as well. Thus, construction of a new 8.2 million tons-per-year (390 Bcf-per-year) liquefaction plant could cost between $1.5 and $2 billion—50 percent for construction-related costs, 30 percent for equipment, and 20 percent for bulk materials.[19]

LNG companies build most LNG ships for a specific project, then own and operate them thereafter. Construction costs have dropped from $280 million in 1995 (for a 138,000-cubic-meter-capacity ship) to $150 to $160 million today—still more than double the cost of a crude oil tanker. Most added costs relate to the construction of insulated tanks.[20] LNG shipping costs vary based on the ship's operating and amortization costs, the size of the cargo, and the distance transported.[21]

The costs of building and operating receiving terminals (unloading, storage, and regasification facilities) vary by site. In the United States, new onshore terminals built on existing designs are expected to cost $400 million or more.[22] The cost of constructing offshore LNG facilities is substantially higher.

Deutsche Bank has estimated that worldwide capital expenditures in the LNG sector between 2003 and 2010 may total $114 billion.[23] The International Energy Agency has estimated that worldwide investments in LNG liquefaction, shipping, and regasification may total $252 billion between 2001 and 2030.[24] Uncertainties in projecting future LNG investment include the costs of

The LNG Value Chain

	Exploration & Production	Liquefaction	Shipping	Storage & Regasification
	Gas production and preplant processing and transport	Liquefaction plant, including preliquefaction processing, storage, and carrier loading	Shipping	Receiving terminal, including unloading, storage, regasification, and delivery
% Total Capital Costs (EIA, 2003)	15 to 20	30 to 45	10 to 30	15 to 25
Example Capital Costs	Varies widely	$1.5 to $2 billion for a plant that produces 8.2 million tons of LNG per year	$155 million to purchase a single 138,000 cubic meter ship, or $60,000 per day to charter	$400 million for a U.S. terminal capable of delivering between 180 and 360 Bcf per year

LNG infrastructure, natural gas prices, competition from other fuels, technology, environmental requirements, and geopolitical trends.

The magnitude of the total investment required to build and operate a complete LNG value chain (approximately $7–10 billion) requires the sort of economic power historically held by only countries or very large corporations. One way to minimize the substantial risks has been to obtain long-term supply contracts (20–25 years in duration), with a “take or pay” clause that obligates buyers to pay for gas at a certain price, even if markets do not exist.

Complementing long-term contracts, a spot market and short-term contracts[25] have emerged in the last five years. Factors influencing the emergence of the spot market include some global overcapacity in liquefaction, an increase in the number of LNG tankers, and increased contractual flexibility across the various components of the LNG value chain. These factors make it easier for exporters to sell their LNG and for importers to buy LNG, when and where it makes the most economic sense.

In the United States, LNG imports delivered under spot-market contracts represented more than 80 percent of all LNG imports in 2003, and nearly 70 percent in 2004. By contrast, in 1998 only about 25 percent of all LNG imports to the United States were delivered under spot-market contracts. The larger supply of spot-market LNG imports reflects the growing importance of the spot market to supply marginal demands in the United States, with volumes rising and falling in response to natural gas prices.[26] The spot market now accounts for almost 12 percent of the total worldwide LNG market, a number that could rise to 15 to 20 percent during the next 10 years,[27] creating increased opportunity for growth in both the size and efficiency of the LNG business.

16 When the full cost of exploration and production are attributed solely to an LNG opportunity, the cost for this component can see substantial increases.

17 Within the context of LNG, a “train” consists of the series of linked equipment elements used in the liquefaction process.

18 Sen, C. Taylor, Trends and Developments in the LNG Industry, an Appendix of *Potential Supply of Natural Gas 2002*, published by the Potential Gas Committee, pp. 89-98.

19 GTI, as referenced in the *The Global Liquefied Natural Gas Market: Status and Outlook* by the Energy Information Administration DOE/EIA-0637 (2003), p. 43.

20 GTI, DOE/EIA-0637, (2003) p. 44.

21 LNG Shipping Solutions, as referenced in *The Global Liquefied Natural Gas Market: Status and Outlook* by the Energy Information Administration DOE/EIA-0637 (2003), p. 44.

22 *National Gas Intelligence*, Intelligence Press, Inc., October 28, 2004.

23 Deutsche Bank, *Global LNG: Exploding the Myths*, 2004.

24 International Energy Agency, *World Energy Investment Outlook 2003*.

25 Definitions vary for the duration of short-term contracts, e.g. 2 years or less (DOE, FE) and 4 years or less (International Group of Liquefied Natural Gas Importers).

26 DOE Office of Fossil Energy.

27 GTI, DOE/EIA-0637.

Delivery & End Use

The LNG chain provides natural gas consumed in homes and manufacturing and power generation facilities.

Frequently Used Conversions

To:	Billion Cubic Meters of Natural Gas	Billion Cubic Feet of Natural Gas	Million Tons of LNG	Trillion Btu
From:	MULTIPLY BY			
1 Billion Cubic Meters of Natural Gas	1	35.315	0.760	38.847
1 Billion Cubic Feet of Natural Gas	0.028	1	0.022	1.100
1 Million Tons of LNG	1.136	46.467	1	51.114
1 Trillion Btu	0.026	0.909	0.020	1

Typical Liquid–Vapor Conversions*

To:	Liquid Measures			Vapor Measures		Heat Measure
From:	Metric Ton LNG	Cubic Meter LNG	Cubic Foot LNG	Cubic Meter Natural Gas	Cubic Foot Natural Gas	Btu*
	MULTIPLY BY					
1 Metric Ton LNG	1	2.193	77.445	1,316	46,467	51,113,806
1 Cubic Meter LNG	0.456	1	35.315	600.00	21,189	23,307,900
1 Cubic Foot LNG	0.0129	0.0283	1	16.990	600.00	660,000
1 Cubic Meter Natural Gas	0.000760	0.001667	0.058858	1	35.315	38,847
1 Cubic Foot Natural Gas	0.000022	0.000047	0.001667	0.02832	1	1,100

Conversion Factors

1 million metric tons/year = 1.316 billion cubic meters/year (gas) = 127.3 million cubic feet/day (gas)

1 billion cubic meters/year (gas) = 0.760 million metric tons/year (LNG or gas) = 96.8 mcf/day (gas)

1 million cubic feet/day (gas) = 10.34 million cubic meters/year (gas) = 7,855 metric tons/year (LNG or gas)

Source: DOE Office of Fossil Energy

* Based on a volume conversion of 600:1, LNG density of 456 kg per cubic meter of LNG, and 1,100 gross dry Btu per cubic feet of gas.

The Basics of Natural Gas Production

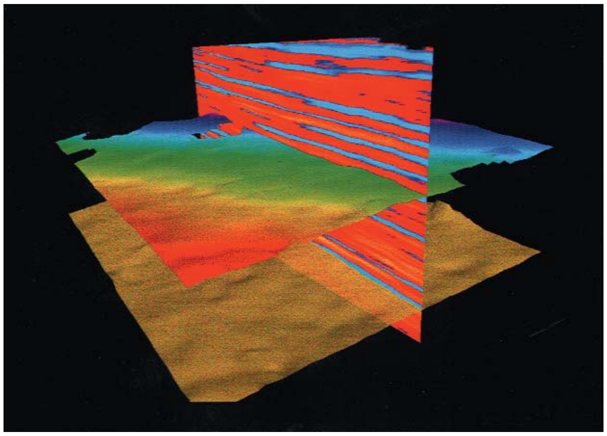
Exploring for natural gas deposits is a high-risk, high-cost endeavor—millions or tens of millions of dollars may be spent by a firm with the result being a "dry hole." Exploration begins when a firm or group of firms acquires an onshore or offshore parcel on which to drill. The firm then develops a prospect—often using sophisticated seismic imaging technologies (as shown below) to identify a target zone with a higher probability of containing hydrocarbons.

Once the necessary environmental assessments and permits are obtained—a process that can take two or more years in many areas—the firm engages a contractor to drill and complete an exploratory well. If tests indicate a possible economic accumulation of natural gas (known as a "discovery"), one or more delineation wells are drilled to confirm the extent of the accumulation and provide additional properties of the rocks and fluids.

Significant financial resources—hundreds of millions to more than one billion dollars—must then be committed to drill wells, design and construct a gas gathering and processing system, and connect the field via pipeline to one or more markets. For an LNG supply project, the pipeline must be laid from the field to a liquefaction plant at a coastal location. Production operating costs and royalty and tax payments are also part of the ongoing cost after a liquefaction plant begins operation. For each million tons per year of LNG (47 Bcf per year) produced by a liquefaction plant during a 20-year period, about 1.5 Tcf of natural gas reserves are required.[28]

FIGURE 9

A seismic image of subsurface features, including petroleum resources.



Source: Texaco Production Operations

Producing LNG by Liquefaction

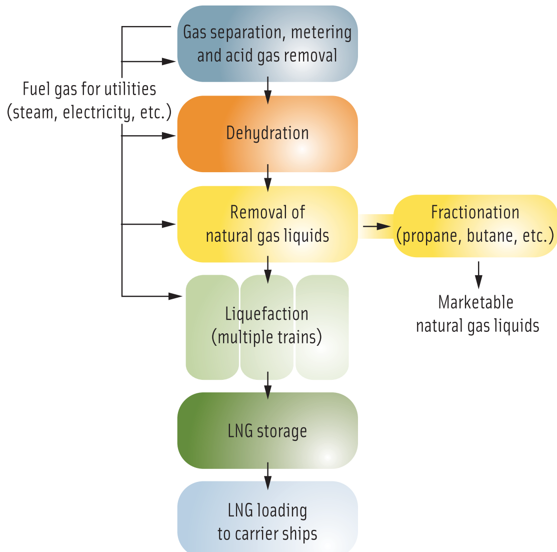
Figure 10 illustrates the components of an LNG liquefaction plant. The raw feed gas supply arriving from a producing gas field must be clean and dry before liquefaction can take place. It is scrubbed of entrained hydrocarbon liquids and dirt and treated to remove trace amounts of two common natural gas contaminants: hydrogen sulfide and carbon dioxide. Next, the gas is cooled to allow water to condense and then further dehydrated to remove even small amounts of water vapor. If mercury is present in the feed gas, it must be removed at this stage. The clean and dry gas may then be filtered before liquefaction begins. It is important that the gas consist primarily of methane with only small amounts of light hydrocarbons to ensure an efficient process.

Liquefaction takes place through cooling of the gas using heat exchangers. In these vessels, gas circulating through aluminum tube coils is exposed to a compressed hydrocarbon-nitrogen refrigerant. Heat transfer is accomplished as the refrigerant vaporizes, cooling the gas in the tubes before it returns to the compressor. The liquefied natural gas is pumped to an insulated storage tank where it remains until it can be loaded onto a tanker.

The liquefaction process can have variations. For example, the Phillips Cascade process, originally developed for the Kenai, Alaska liquefaction plant, employs three heat exchangers with successively colder refrigerants (propane, ethane, methane) and independent compressors for each exchanger-refrigerant combination. Together the series of exchangers comprise a single LNG train. The Mixed Components Refrigerant (MCR®) process developed by Air Products and Chemicals Inc., employs a single large heat exchanger and a single compressor using a mixture of refrigerants in each train. The gas is also pre-cooled using propane as a refrigerant. This system has the advantage of fewer compressors and exchanger elements. A number of variations on these processes have been developed in the past decade.[29]

FIGURE 10

Components of an LNG liquefaction plant.



The Kenai, Alaska liquefaction facility was America's first. It has exported LNG to Japan for more than 30 years.

After liquefaction, the LNG is stored in insulated tanks until it can be loaded onto carrier ships. This photo shows such tanks in Trinidad and Tobago.

LNG is transferred from storage tanks (like these in Qatar) to the carrier ship via specially constructed loading systems.

In the United States, large-scale liquefaction occurs at the Kenai, Alaska facility in preparation for exporting LNG to Japan. Generally, however, liquefaction occurs overseas. A typical LNG liquefaction facility includes three or four trains, although the plant in Bontang, Indonesia has eight. Worldwide, there are currently 18 liquefaction plants that export LNG operating 71 trains. Another 14 trains were under construction as of February 2005.[30]

The LNG production capacity of individual trains has increased from 0.5 to 1 million tons per year for the early plants to 1 to 5 million tons per year for plants under construction. This trend has been matched by a five-fold increase in LNG storage tank size, from 40,000 cubic meters to 200,000 cubic meters. While steam turbines were used as mechanical compressor drivers in early plants, more efficient natural gas turbines are now standard. Continual evolution in both turbine and compressor designs has resulted in a steady decrease in the power required to liquefy natural gas.

LNG formed in each train—the natural gas now at about –260°F—is transferred to insulated tanks for storage at atmospheric pressure. Just as the temperature of boiling water remains constant even if heat is added (thanks to the thermodynamics of steam evaporation), so does the temperature of boiling LNG at atmospheric pressure—as long as the gas vapor (LNG "steam") is removed. This "boil off" gas, about 0.15 percent of the volume per day, fuels the liquefaction facility, LNG transport ships, and receiving terminals where LNG is regasified.

At the liquefaction plant, LNG is transferred from the storage tanks to the ship using specially constructed pumps and jointed loading pipes that are designed to withstand the very low ("cryogenic") temperatures necessary for liquefaction.

28 Sen, C. Taylor, Trends and Developments in the LNG Industry, an Appendix of *Potential Supply of Natural Gas 2002*, published by the Potential Gas Committee, pp. 89-98.

29 Air Products and Chemicals, *LNG Capabilities*, August 2000.

30 DOE Office of Fossil Energy internal analysis.

The Global Business of LNG Transport

Transportation accounts for 10 to 30 percent of the cost of the LNG value chain. Carrier ships often are owned by LNG producers, but also sometimes are built as independent investments separate from specific LNG projects.

The evolution of LNG transport ships has been dramatic. While the first LNG carrier was a converted freighter with aluminum tanks insulated with balsa wood, modern LNG carriers are sophisticated double-hulled ships specifically designed for the safe and efficient transportation of cryogenic liquid. In May 2005, 181 LNG carriers were operating, with another 74 under construction for delivery in the 2005-07 time frame.[31]

About half of the LNG fleet is of the *membrane* design, with the other half of the *spherical* or *Moss*® design.[32] Figure 11 depicts the two types of ships.[33]

As of 2004, about three-fourths of the new LNG ships under construction or planned were of the membrane design due to innovations aimed at increasing cargo capacity in a given hull size, reducing capital costs and overall construction time.[34]

A small number of ships in service, built by the IHI shipyard in Japan, feature a self-supporting *prismatic tank design*. Like the spherical tank, the prismatic tank is independent of the hull. Any leaking LNG evaporates or flows into a pan below the tank.

FIGURE 11

The two basic types of LNG carrier ships have distinctive shapes.

The membrane design tanker introduced in 1970 features multiple tanks with linings made from thin (0.5 mm) nickel steel (Invar®) alloy capable of withstanding extreme temperatures. These tanks are integrated into the hull of the ship.

The spherical design tanker introduced in 1971 features round containment tanks that sit on supports on the hull of the ship and transfer the stress of thermal expansion and contraction onto those supports.

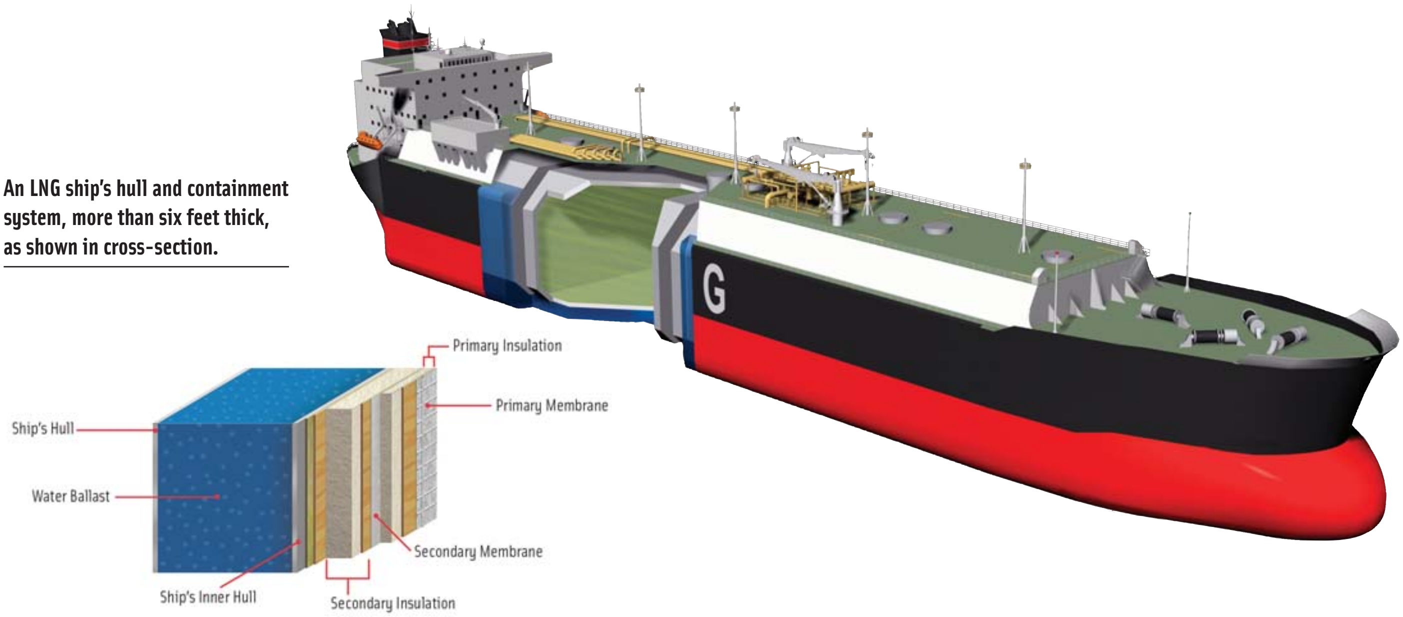
31 Colton Company, Worldwide Construction of Gas Carriers.

32 Data from the Society of International Gas Tanker & Terminal Operators (SIGGTO) show that Moss tankers represented 46 percent of the fleet in 2004, membrane tankers accounted for 51 percent, and 3 percent were other designs. In 2006, 43 percent are anticipated to be Moss, 54 percent membrane, and 3 percent other.

33 South Korea is the world's leading builder of LNG ships, led by Hyundai Heavy Industries Co., Ltd., Samsung Heavy Industries, and Daewoo Shipbuilding & Marine Engineering Co. Japan places second with major firms including Mitsubishi Heavy Industries Ltd., Mitsui Engineering and Shipbuilding Co., and Kawasaki Heavy Industries Ltd. Izari in Spain and Chantiers de l'Atlantique in France are also leading builders of LNG ships. Parker, Leia, *Investors Build Ships, Anticipating Boom in Gas Imports*, Dow Jones Newswire, October 28, 2003.

34 Harper, Ian, *Future Development Options for LNG Marine Transportation*, paper presented at the American Institute of Chemical Engineers, Spring National Meeting in New Orleans, March 10-14, 2002. Also see www.coltoncompany.com.

An LNG ship's hull and containment system, more than six feet thick, as shown in cross-section.



Source: Neil Chapman, BP; image courtesy of BP

SAFEGUARDING MARITIME TRANSPORT

Due to comprehensive safety and security programs for LNG tankers and receiving terminals, more than 33,000 shipments have transported in excess of three billion cubic meters of LNG without a serious accident at sea or in port in the past 40 years. LNG facilities and vessels feature state-of-the-art natural gas, fire, and smoke detection systems that identify hazardous situations and automatic shutdown systems that halt operations.

Security measures for the waterfront portions of marine terminals and LNG ships are regulated by the U.S. Coast Guard, which prevents other ships from getting near LNG tankers while in transit or docked at a terminal. The Federal Energy Regulatory Commission (FERC) also serves as a coordinator with the Coast Guard and other agencies on issues of marine safety and security at LNG import facilities.

In October 2003 the Coast Guard issued final rules to meet new security requirements mandated by the Maritime Transportation Security Act of 2002. These regulations cover vessels and facilities operating on or adjacent to waters under U.S. jurisdiction and require security assessments of ports, vessels, and facilities. Owners or operators of certain marine assets must develop preventive security plans as well as response plans for potential industrial incidents and security breaches.[35] Port-level security committees must focus on security shortfalls and contingency plans that will protect port assets at each threat level.

The Coast Guard has led the International Maritime Organization (IMO) in developing maritime security standards outside U.S. jurisdiction. These new standards, the International Ship and Port Facility Security Code (ISPS Code), contain detailed mandatory security requirements for governments, port authorities, and shipping companies as well as recommended guidelines for meeting those requirements. The ISPS Code is intended to provide a standardized, consistent framework to aid governments in evaluating risk.[36]

In 2004 FERC entered into an agreement with the Coast Guard and the Department of Transportation to establish roles and responsibilities for each agency regarding LNG security and to assure that each agency quickly identifies and addresses problem areas.[37]

35 *Protecting America's Ports*, July 1, 2003, and *Making Our Waters Safer*, October 22, 2003, U.S. Department of Homeland Security press releases related to the Maritime Transportation Security Act of 2002.

36 Parfomak, Paul W., *Liquefied Natural Gas (LNG) Infrastructure Security: Background and Issues for Congress*, Congressional Research Service, CRS Report to Congress, September 9, 2003.

37 *Commission, Coast Guard, DOT Sign Interagency Aagreement to Coordinate Review of LNG Terminal Safety*, Federal Energy Regulatory Commission Press Release, February 11, 2004.

Preparing LNG for Use by Regasification

At a marine terminal or satellite installation, pumps transfer LNG from storage tanks to warming systems, where the liquid rapidly returns to a vaporized state. *Ambient temperature* systems use heat from surrounding air or from seawater (even in cold weather, both are warmer than LNG) to vaporize the cryogenic liquid, while *above-ambient temperature* systems add heat by burning fuel to indirectly warm the LNG via an intermediate fluid bath.[38]

Afterward, the natural gas is ready for delivery into the nation's network of transmission and distribution pipelines for use by residential consumers, industries, or nearby power generation plants, where it fuels natural gas turbines.

The benefits of storing LNG. Stored LNG supplies help to meet consumption needs during the coldest days of winter, particularly for gas utilities with a substantial residential customer base and therefore a highly seasonal demand for gas. On these peak-demand days, LNG storage facilities prove invaluable because of their ability on short notice to regasify and deliver large amounts of natural gas into regional distribution systems. About 82 percent of LNG storage capacity is located in the eastern United States, as reflected in the map on page

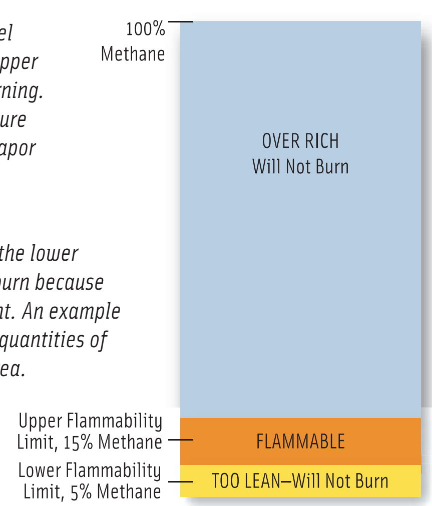
38 *Oil and Gas Journal*, 2003 LNG World Trade and Technology, November 2003.

LNG vapor has a limited flammability range.

The physical and chemical properties of LNG render it safer than other commonly used hydrocarbons.

Lack of oxygen prevents fuel concentrations above the upper flammability limit from burning. An example would be a secure storage tank with an LNG vapor concentration at or near 100 percent methane.

Fuel concentrations below the lower flammability limit cannot burn because too little methane is present. An example would be leakage of small quantities of LNG in a well-ventilated area.



7, with most of this capacity concentrated in the Northeast for use in major population centers such as Boston, New York, and Philadelphia.[39]

Modern LNG storage techniques. Prior to regasification, LNG is stored at atmospheric pressure in double-walled, insulated tanks that feature innovative, highly safe, and stable designs. The walls of the inner tank, composed of special steel alloys with high nickel content as well as aluminum and pre-stressed concrete, must be capable of withstanding cryogenic temperatures. LNG storage tanks are built on a base of concrete blocks with the glassy volcanic aggregate perlite added to Portland cement and special admixtures, reinforced with steel bars. These blocks insulate the cryogenic tank from the ground itself. Perlite is also used as insulation in the walls of the tank.

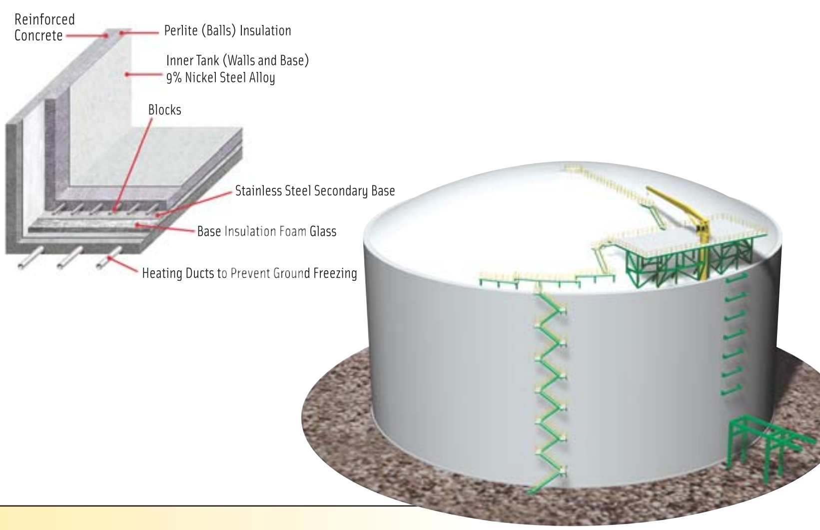
To safeguard against leaks, some storage tanks feature a double-containment system, in which both the inner and outer walls are capable of containing LNG. Another approach, utilized by most LNG tanks at existing U.S. import and satellite storage facilities, surrounds a single-containment tank with an earthen dam or dike that provides secondary containment, safely isolating any LNG spills.

39 EIA, *LNG Markets and Uses: June 2004 Update.*

Regasification system at the Lake Charles, Louisiana LNG terminal

A cross-section of storage tank walls totaling about five-and-a-half feet thick

Source: Neil Chapman, BP; image courtesy of BP



HOW ARE LNG FACILITIES KEPT SECURE AND SAFE?

Security for land-based LNG facilities and onshore portions of marine terminals is regulated by the Federal Energy Regulatory Commission (FERC) and U.S. Department of Transportation (DOT). Requirements include security patrols, protective enclosures, lighting, monitoring equipment, and alternative power sources. Federal regulations also require exclusion zones surrounding LNG facilities to protect adjacent sites from heat in the event that vapor clouds are formed in a release and are ignited.

LNG security is multifaceted. Interstate natural gas companies receive security updates and alerts from the Federal Bureau of Investigation and other federal agencies. DOT's Office of Pipeline Safety provides guidelines to LNG operators for security procedures at onshore facilities. A federal security task force works to improve pipeline security practices, facilitate communications within industry and government, and lead public outreach efforts. FERC works with other federal agencies and industry trade groups on regional contingency planning for interrupted service from the main natural gas pipeline. Security is also a prime consideration in the approval process for new or expanded facilities. Depending on the specifics of a project, FERC may convene special technical conferences with other government and law enforcement agencies to address safety and security issues. The Department of Homeland Security is the nation's lead federal agency for protecting critical infrastructure, working closely with state and local government, other federal agencies, and the private sector, which owns ands operates the lion's share of the nation's critical infrastructure and key assets.[40]

Comprehensive safety procedures and equipment found at all LNG facilities help to maintain an outstanding record of worker safety. Precautions include avoiding asphyxiation (which can result if LNG vapors deplete breathable oxygen in a confined space), preventing lung damage (which can result if LNG vapors are inhaled), and preventing cryogenic burns (which can occur if LNG contacts human skin).

40 U.S. Department of Homeland Security, *The National Strategy for the Physical Protection of Critical Infrastructures and Key Assets*, February 2003.

Ensuring Consistent Quality for End Use

Raw natural gas intended for use in the United States today contains nonmethane components such as ethane, propane, and butane that must be "stripped" to leave pure methane. Methane then flows through the pipeline to end users. Recently, with U.S. natural gas supplies tightening and prices on the rise, pressure has mounted to allow natural gas to flow into the grid with some impurities remaining. This "richer" gas with higher heating values can produce a flame that is too large or too hot in certain applications, making it incompatible with U.S. appliances and industrial processes as well as the gas quality standards of local utilities and pipelines.[41]

The composition of LNG received in the United States varies by country of origin, as shown in Table 1, and must be modified before delivery. This variation limits deliveries to certain terminals and also must be factored into the development of new facilities. LNG importing facilities deal with this problem by mixing domestic and imported gas or injecting nitrogen or air into the gas stream.

At Lake Charles, Louisiana, Southern Union successfully mixes high-heat-content natural gas with relatively low-heat-content gas common to the region's substantial processing infrastructure. Therefore, LNG deliveries with high Btu content occur more often at Lake Charles than at the three East Coast terminals.

TABLE 1

Typical Composition of LNG Imports by Country

Origin	Methane (C1) %	Ethane (C2) %	Propane (C3) %	Butane (C4+) %	Nitrogen (N2) %
Algeria	87.6	9.0	2.2	0.6	0.6
Australia	89.3	7.1	2.5	1.0	0.1
Malaysia	89.8	5.2	3.3	1.4	0.3
Nigeria	91.6	4.6	2.4	1.3	0.1
Oman	87.7	7.5	3.0	1.6	0.2
Qatar	89.9	6.0	2.2	1.5	0.4
Trinidad & Tobago	96.9	2.7	0.3	0.1	0

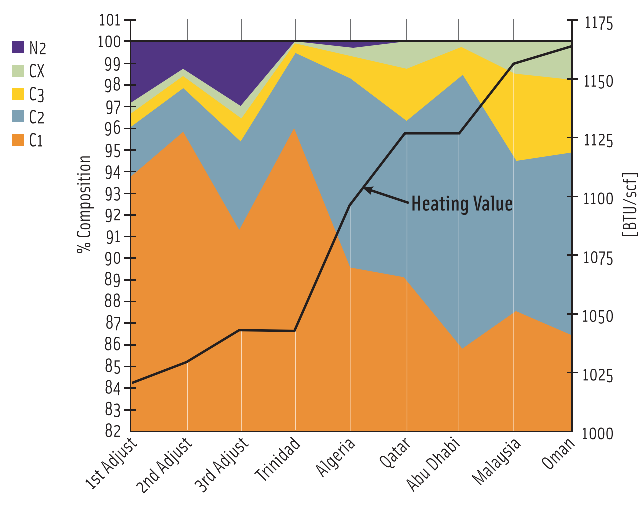
Source: Groupe International Des Importateurs De Gaz Natural Liquéfié

At the Everett, Massachusetts facility, Distrigas uses in-tank blending of pipeline gas with LNG to meet standards. Btu levels can also be reduced by injecting nitrogen or air into the vaporized gas stream at sendout. This method can be costly: approximately $18.5 million to equip a facility with air injection devices and about $28 million for nitrogen separation equipment. Dominion is in the process of installing a nitrogen separation plant at its Cove Point facility. Installation of liquid-stripping facilities at marine terminals also would effectively allow Btu reduction, but at a cost of $30 million or more per facility.

Since February 2004 FERC and DOE have been working with industry to address concerns about LNG interchangeability and current natural gas quality standards, particularly in light of expected increases in LNG imports. Natural gas industry stakeholders involved in this collaborative process include producers, pipelines, local distribution companies, process gas consumers, liquefied natural gas importers, equipment manufacturers, turbine manufacturers, and electric utilities.

FIGURE 12

Imported LNG can have a composition and heating value that differ from average U.S. pipeline gas.



LNG cargos imported into the U.S. exhibit a range of heating values.

Source: Rue, David, GTI Gas Technology Conference, Phoenix, February 11, 2004

41 Foss, Brad, The Associated Press, *Inconsistent Quality of Natural Gas Raises Safety Concerns*, 2004.

Informed

Decision Making

As U.S. demand for natural gas continues to grow, the nation is likely to turn more and more to natural gas found in other parts of the world. LNG provides access to this large global natural gas supply. Today, the United States has only six LNG receiving terminals—four on the mainland, one offshore, and one in Puerto Rico. In the future, new and expanded LNG terminals will be necessary to ensure clean, reliable, and affordable supplies of energy for American consumers.

Although significant progress has been made to streamline the LNG permitting process, it remains complex and lengthy. As many as 100 permits and approvals may be required from federal, state, and local government agencies for a new onshore LNG terminal. These agencies rigorously examine the benefits of the proposed project, and take into account facility design, location, safety, and security as well as environmental concerns to arrive at the best, most informed decisions. Without significant delays, it may take up to seven years to bring a new onshore terminal on-line, from initial design to the first delivery of LNG imports, including up to three years for obtaining necessary permits and approvals.[42]

KEY ISSUES FACING DECISION MAKERS

- Security and safety
- Need to streamline permitting
- Siting, land use, and environmental issues
- National, regional, and local economic benefits
- Gas quality/LNG interchangeability
- Return on investment/Financing
- Sustainable development, including societal implications of LNG trade
- Technology innovation
- Communication/Public understanding

Federal, State, and Local Decision Makers

Numerous federal agencies oversee the nation's LNG infrastructure, working with the states and local authorities. For example:

The Federal Energy Regulatory Commission (FERC) asserts approval authority over the place of entry and exit, siting, construction, and operation of new terminals as well as modifications or extensions of existing LNG terminals (see 18 CFR 153). FERC requirements include detailed site engineering and design information, evidence that an LNG facility will safely receive or deliver LNG, and delineation of a facility's proposed location and geologic risk, if any. Facilities to be located at the Canadian or Mexican border for import or export of natural gas also require a Presidential Permit. Every two years, FERC staff members inspect LNG facilities to monitor the condition of the physical plant and review changes from the originally approved facility design or operations. FERC has jurisdiction over all existing LNG import terminals and 15 peak-shaving plants involved in interstate gas trade.

The U.S. Coast Guard (USCG) is responsible for assuring the safety of marine operations in U.S. coastal waters under provisions of the Ports and Waterways Safety Act of 1972 (P.L. 92-340) and also the Maritime Transportation Security Act (MTSA). The latter was signed into law in November 2002, amending the Deepwater Port Act of 1974 (DWPA) to include offshore natural gas facilities. The USCG implements a streamlined application process mandated by the DWPA that is designed to yield a decision within one year of receipt of an application for construction of an offshore LNG terminal. The USCG also regulates the design, construction, and operation of LNG ships and the duties of LNG ship officers and crews.

42 National Petroleum Council, LNG Subgroup Report, updated August 2004.

The Department of Transportation Office of Pipeline Safety regulates the siting and safety of LNG pipeline facilities, including LNG peak-shaving plants, under the Pipeline Safety Act of 1994 (P.L. 102-508), as amended. Implementing regulations for the Act, including provisions on facility siting, are found in 49 CFR 191-199. Standards for operation, maintenance, fire protection, and security at such facilities are chiefly found in 49 CFR 193 and incorporate National Fire Protection Association (NFPA) standards.

The Department of Energy (DOE) Office of Fossil Energy coordinates across federal agencies that have regulatory and policy authority for LNG. The Natural Gas Act of 1938 requires that anyone seeking to import or export natural gas across U.S. borders must be authorized by DOE. DOE monitors LNG shipments to ensure the integrity of American energy supplies via a certification process. In addition, the Office of Fossil Energy and the National Energy Technology Laboratory fund LNG technology research and work to eliminate or minimize potential impediments to LNG facility siting and operations.

Jurisdiction among federal agencies with LNG oversight responsibilities is sometimes a point of contention, and memorandums of understanding are established to delineate respective agency roles. For example, in May 2004 a final memorandum of understanding for interagency coordination on licensing of deepwater ports, pursuant to the Deepwater Port Act, was established involving the Departments of Commerce, Defense, Energy, Homeland Security, Interior, and Transportation, the Environmental Protection Agency (EPA), FERC, the Council on Environmental Quality, and the U.S. Corps of Engineers.

Protecting Our Environment

The National Environmental Policy Act (NEPA) requires that federal agencies consider impacts to the environment of all proposals for major federal actions and, when appropriate, consider alternatives to those proposals. FERC—as the lead agency for the permitting of natural gas pipelines, compressor

Organizations involved in LNG facility decisions

Federal Agencies

Onshore/Marine
- U.S. Department of Energy
- Federal Energy Regulatory Commission
- U.S. Coast Guard
- U.S. Department of Transportation
- U.S. Environmental Protection Agency
- U.S. Minerals Management Service
- U.S. Fish and Wildlife Service
- U.S. Dept. of Labor/Occupational Safety & Health Administration
- U.S. Army Corps of Engineers

Offshore
- U.S. Department of Energy
- U.S. Coast Guard
- U.S. Department of Transportation
- U.S. Fish and Wildlife Service
- National Oceanic and Atmospheric Administration
- U.S. Dept. of Labor/Occupational Safety & Health Administration
- U.S. Army Corps of Engineers
- U.S. Environmental Protection Agency
- U.S. Minerals Management Service
- U.S. Maritime Administration

State and Local Agencies
- State departments of environmental protection
- Local governments
- Fire departments
- Police

Non-Governmental Standards Organizations
- National Fire Protection Association
- American Society of Mechanical Engineers
- American Society of Civil Engineers
- American Petroleum Institute
- American Concrete Institute
- American Society for Testing and Materials

stations, storage facilities, and onshore LNG terminals—implements NEPA requirements. Several other federal agencies are also involved.

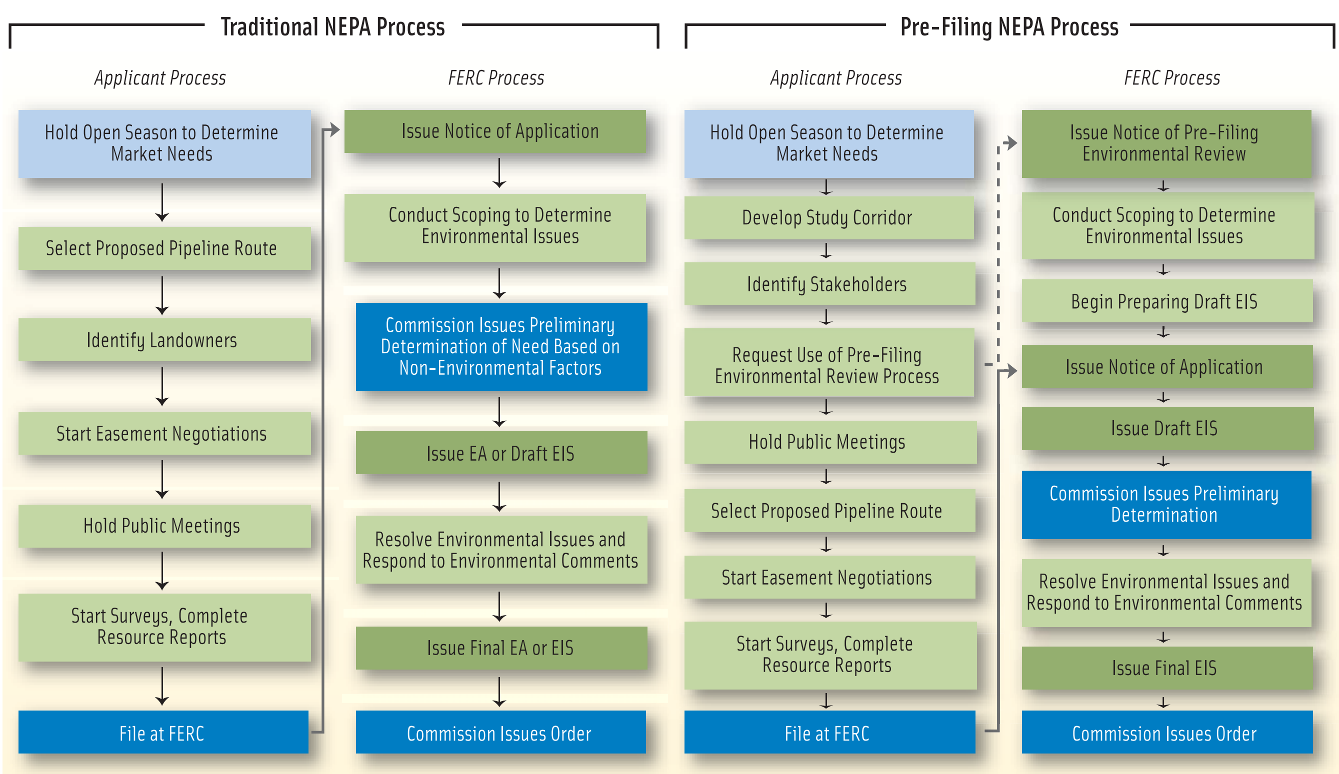
The NEPA process includes open consultation with relevant agencies and the public. Although most applicants notify and meet with the public in advance, the traditional NEPA process begins after an application is filed. In 2002 FERC implemented the optional NEPA pre-filing process, bringing stakeholders together earlier in project review and development to uncover disagreement and work toward resolution before the formal application is filed. The pre-filing NEPA process can accelerate the permitting process by more than six months. Similarly, the DWPA requires NEPA compliance for the permitting of offshore LNG terminals. The Coast Guard is the lead federal agency for the environmental review process and ensures that the application complies with all aspects of NEPA.

State and Local LNG Regulation

The regulation of LNG facilities by states varies from comprehensive to fragmented, and many states are striving to address the evolving interest in LNG. Some state agencies, such as state public utility commissions, govern commerce and trade. Other state regulatory agencies (for example, state departments of environmental protection), together with the U.S. EPA, grant permits for specific activities to minimize environmental impacts. The California Energy Commission provides the leadership for an LNG Interagency Permitting Working Group to ensure close communication among, and support for, agencies potentially involved in the permitting process of any LNG facility.[43]

State and local government agencies are also involved in zoning, construction, operation, and maintenance of LNG terminals. Local fire and police departments have jurisdiction on the basis of protecting the safety and security of the surrounding area.

NEPA pre-filing can expedite the permitting process for onshore LNG facilities by more than six months (blue indicates FERC staff activities; green indicates applicant activities).



Source: Adapted from schematics found at www.ferc.gov/for-citizens/my-rights/process.asp

Safety and security systems rely on personnel who are well trained on operational and maintenance procedures. Organizations such as the Society of International Gas Tanker and Terminal Operators, Gas Processors Association, and National Fire Protection Association (NFPA) have guidelines and provide training based on industry best practices. NFPA, for example, has developed fire safety codes and standards drawing on the technical expertise of diverse professionals—and on technical standards developed by organizations such as the American Society of Mechanical Engineers and the American Society of Civil Engineers.[44]

The Citizens' Role in Facility Location Decisions

Regulatory processes for LNG facility siting and expansion encourage open public consultation and comment, which are key to successful project planning and development. Informed decision making increases certainty that safer and more secure projects with a high degree of environmental integrity are approved.

Opportunities for public participation exist at many stages of the permitting process. Generally, the public first receives notice of a facility project when the company proposing the project begins to prepare environmental studies as required for the FERC application, or when a company seeks easement or purchase of land from private landowners or local governments. Once an application is filed, FERC publishes a notification of application in the Federal Register.[45]

Public meetings are required under both the old and revised (pre-filing) FERC approval processes. Such meetings provide a public forum for questions and concerns about proposed projects. The public can also express views in writing directly to FERC. The Environmental Assessment (EA) and Environmental Impact Statement (EIS) processes allow for a public comment period. All comments received during this open comment period, announced in the Federal Register, are addressed in the final EA or EIS.[46]

Individuals can take a more active role by becoming intervenors—a type of formal involvement that requires adherence to FERC regulations. Whether formally or informally, many government agencies encourage the public to stay informed and to participate in the permitting process. Similar opportunities exist for citizen involvement in state and local government decision making. Examples include participating at public hearings, and providing comments on new regulations, the issuance of permits, or regional development plans.

43 See www.energy.ca.gov/lng/working_group.html.

44 University of Houston, *LNG Safety and Security*, October 2003.

45 See www.gpoaccess.gov/fr.

46 More information on the FERC process and public involvement can be found at www.ferc.gov. Two particularly useful documents available at www.ferc.gov/for-citizens/my-rights.asp are *An Interstate Natural Gas Facility On My Land? What Do I Need To Know*, and *Ideas for Better Stakeholder Involvement in the Interstate Natural Gas Pipeline Planning Pre-Filing Process*.

RECENT REGULATORY CHANGES SPUR LNG INVESTMENTS

The Maritime Transportation Security Act of 2002 transferred jurisdiction for offshore natural gas facilities from the FERC to the U.S. Coast Guard, streamlined the permitting process, and allowed owners of offshore LNG terminals access to their entire capacity rather than requiring them to offer capacity to others through an open-season bidding process, known as "open-access." The December 2002 ruling known as the "Hackberry Decision" has the same effect for new onshore facilities under FERC jurisdiction. These rulings acknowledge that LNG import terminals are supply sources rather than part of the interstate gas transportation system. Both rulings also allow LNG terminals to charge for services based on current market conditions rather than based solely on the terminals' cost for providing the services, as previously required. These new policies are intended to encourage the construction of LNG facilities.

Summary

The United States will continue to rely on natural gas even as domestic production is projected to decline. Significant growth in LNG imports can prevent imbalances in future supply and demand that could adversely affect consumers and the U.S. economy. Such growth must include major increases in LNG infrastructure through expansion of existing import terminals and the construction of new facilities. The United States will need more capacity to meet ever-rising natural gas demand.

The focus of the natural gas industry, the public, and federal, state, and local governmental agencies on major upgrades to LNG infrastructure has raised awareness about relevant siting and operational issues. Such dialogue is needed to assure that the use of LNG will be safe and secure and will maintain the integrity of the human and natural environment.

APPENDIX: INFORMATIONAL RESOURCES

Further information on LNG issues can be obtained from a variety of government, industry, and organization sources as represented in the sampling below.

LNG-Related Websites

The *Energy Information Administration (EIA)*, created by Congress in 1977, is a statistical agency of the U.S. Department of Energy (DOE). A variety of LNG statistics and other information can be found on the EIA website, including the latest updates of the *Global Liquefied Natural Gas Market: Status and Outlook* and *U.S. LNG Markets and Uses*. ***www.eia.doe.gov***

The *Federal Energy Regulatory Commission (FERC)* is an independent agency that regulates the interstate transmission of natural gas, oil, and electricity. FERC also regulates natural gas and hydropower projects. The LNG portion of the FERC website includes an LNG overview and provides answers to important questions about all aspects of the value chain and LNG security and safety. ***www.ferc.gov/industries/lng.asp***

The *National Association of Regulatory Utility Commissioners (NARUC)* is a nonprofit organization of governmental agencies engaged in the regulation of U.S. utilities and carriers. The NARUC website contains comprehensive information on its activities and programs (including those related to LNG), testimony and publications, news, upcoming events, and links to state regulatory commissions. ***www.naruc.org***

The *National Energy Technology Laboratory*, the newest of DOE's national laboratories, works to develop breakthrough technologies and approaches that will assure the safe, clean, and affordable use of U.S. fossil energy resources through the 21st century. A search of the website using the keyword LNG reveals papers, presentations, and other information related to a basic understanding of LNG. ***www.netl.doe.gov***

DOE's *Office of Fossil Energy* supports research and policy options to ensure clean, reliable, and affordable supplies of natural gas for American consumers. The Fossil Energy website contains many features concerning natural gas and LNG, including the web feature, *Liquefied Natural Gas–a Basic Understanding.* ***www.fossil.energy.gov***

The *California Energy Commission* serves as the state's primary energy policy and planning agency for keeping historical energy data and meeting future energy needs. This website includes LNG news, FAQs, state energy policy, proposed projects within the state, and guidance on public participation, security, and safety. ***www.energy.ca.gov/lng***

The *Center for Energy Economics at the University of Texas-Austin, Bureau of Economic Geology* hosts a website on the role of LNG in North American energy security. This website provides a variety of LNG reference reports in English and Spanish, such as *Introduction to LNG*, *LNG Safety and Security*, and *The Role of LNG in North American Natural Gas Supply and Demand*. ***www.beg.utexas.edu/energyecon/lng***

The *Center for Liquefied Natural Gas* has attracted more than 50 members, including LNG asset owners and operators, gas transporters, and natural gas end users. The Center's website contains FAQs, quick facts, a historical perspective, discussion of issues, and a multimedia area. ***www.lngfacts.org***

Dominion, headquartered in Richmond, Virginia, is one of the nation's largest producers of energy. This website provides information on Dominion's Cove Point LNG receiving terminal. ***www.dom.com/about/gas-transmission/covepoint/index.jsp***

The *Gas Technology Institute (GTI)* is an independent, not-for-profit technology organization that works with its customers to find, produce, move, store, and use natural gas. A search of the keyword LNG on the GTI website provides visitors with a list of links, including descriptions of LNG research and development at GTI, and other useful documents and information sources. ***www.gastechnology.org***

The National Gas Company of Trinidad and Tobago and four international partners formed the *Atlantic LNG Company of Trinidad and Tobago* in 1995. This website provides information on the company's LNG facilities, the liquefaction process, and natural gas and LNG-related information. ***http://atlanticlng.com***

The *International LNG Alliance* (ILNGA) is sponsored by the United States Energy Association (USEA), the U.S. Member Committee of the World Energy Council (WEC). It works to promote and advance the safe, reliable, cost-effective, and environmentally sound use of LNG, as well as the development of LNG infrastructure. The ILNGA website includes information on the various education, policy, and trade and business development aspects of LNG. ***www.ilnga.org***

Other LNG Information Available Online

Liquefied Natural Gas (LNG) *Infrastructure Security: Background and Issues for Congress* by Paul W. Parfomak of the Congressional Research Service (September 9, 2003; document RL32073) provides an overview of recent initiatives and key policy issues associated with LNG security. ***www.pennyhill.com/infrastructure.html***

The Next Prize by Daniel Yergin and Michael Stoppard is an article in *Foreign Affairs* magazine, Volume 82, No. 6 (Nov/Dec 2003), pp. 103-114, published by the Council on Foreign Relations. This article provides an overview of the newly emerging global gas market and issues related to LNG. ***www.foreignaffairs.org***

Protecting America's Ports, Maritime Transportation Act of 2002 is a brief document published by the U.S. Department of Homeland Security that describes the new regulations of the Maritime Transportation Act of 2002. Included in this document is a fact sheet outlining the implementation requirements and other security initiatives of the new Act. ***www.dhs.gov/interweb/assetlibrary/MTSA_Presskit.doc***

Trends and Developments in the LNG Industry by Dr. Colleen Taylor Sen of the Gas Technology Institute is a 10-page summary included as an appendix to the Potential Gas Committee's 2002 issue of a biennial report: *Potential Supply of Natural Gas*. This summary describes changes in the U.S. LNG market. ***www.mines.edu/research/pga/index.html***

A short video on LNG is available from British Petroleum p.l.c. ***http://www.bplng.com/environment/video.asp***

U.S. Department of Energy
Office of Fossil Energy
www.fossil.energy.gov

National Energy Technology Laboratory
www.netl.doe.gov

August 2005

DOE/FE-0489

Printed on recycled paper

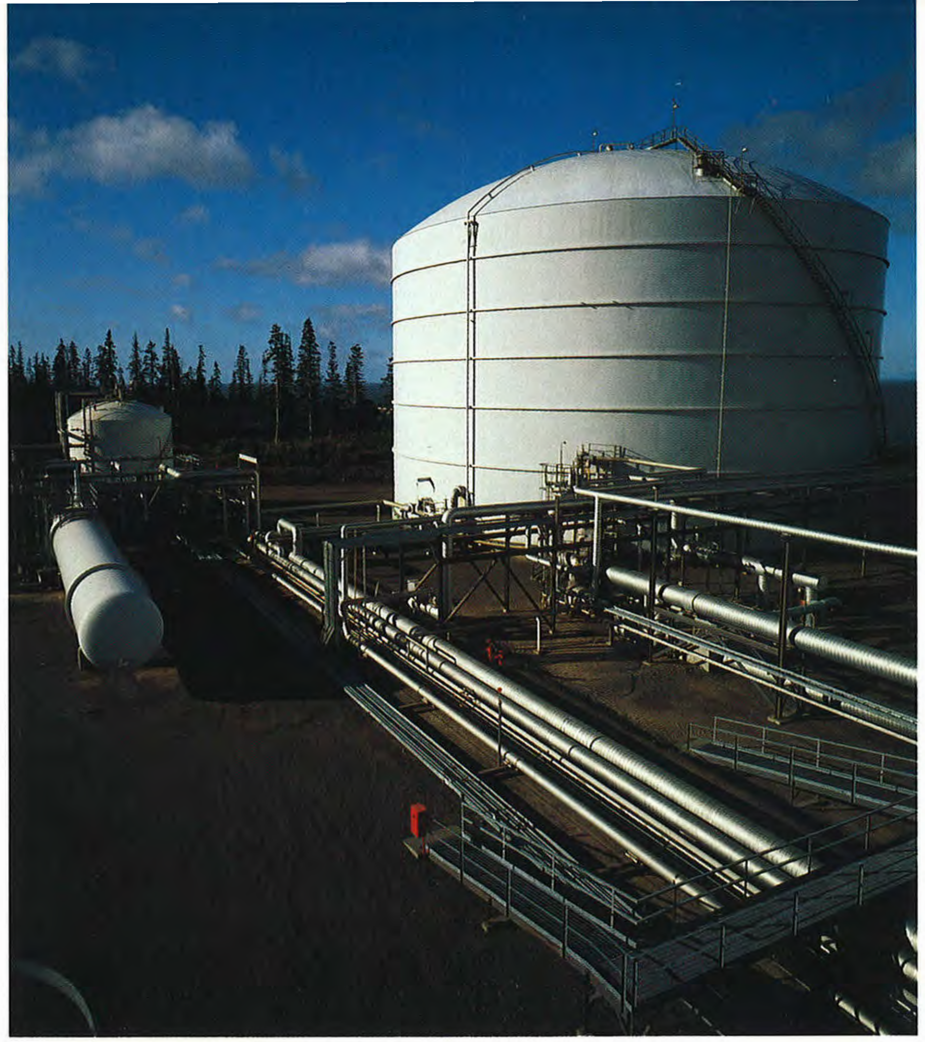
Kenai Liquefied Natural Gas Operations

The Showpiece of an Industry

The Kenai (pronounced KEY-nye) liquefied natural gas project is a success story. Its continuous operation since 1969 demonstrates the exceptional supply dependability of liquefied natural gas — LNG — as a fuel. Since operations began, the plant and ships have compiled an outstanding safety record. The facility has surpassed contract delivery volumes promised to its customers.

The Kenai LNG project also is an example of international cooperation and good will between the United States and Japan. Deliveries have gone like clockwork, and technical coordination and business relations between buyers and sellers have been excellent. In addition to its use as a fuel, super-cold LNG is used in Japan for auxiliary industries — such as refrigeration of fresh tuna and manufacture of liquid oxygen and nitrogen.

These factors make the Kenai project a showpiece of the LNG industry and an example of the value and potential of LNG to Alaska, the Pacific Rim and the world.



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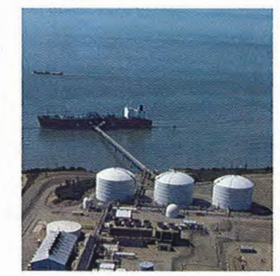
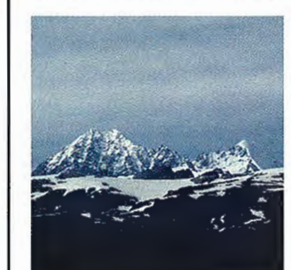
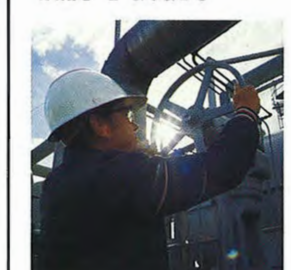






The Product

The plant manufactures LNG from natural gas, which is more than 99 percent methane, by reducing the temperature to -259° Fahrenheit (-161° Celsius). This changes the natural gas from a vapor to a liquid and shrinks the gas to less than 1/600th of its original volume, making long-distance shipping feasible. LNG is less than half as dense as water, is colorless, odorless, non-toxic and sulfur free. LNG is stored at receiving terminals as a liquid and vaporized as needed for use as a high-quality fuel.

The Companies

Phillips Petroleum Company holds a 70 percent interest in the Kenai plant — which it operates — and two LNG tankers. The company has its headquarters in Bartlesville, Oklahoma, where it was founded in 1917.

Phillips is the largest producer of natural gas liquids — a different product from LNG that includes such hydrocarbons as propane and butane — in the United States. The company also produces nearly 1.5 billion cubic feet of natural gas daily worldwide. Its GPM Gas Corporation subsidiary, based in Houston, processes more than 1.4 billion cubic feet of natural gas daily — making it the nation's largest natural gas processor. Natural gas and gas liquids are pivotal to Phillips' integrated operations, furnishing gas liquids for the company's chemicals and refining businesses.

In addition to its natural gas interests, Phillips is engaged in:

- Petroleum exploration and production on a worldwide scale.
- Petroleum refining and marketing in the United States.
- Chemicals production and distribution worldwide.
- Specialty chemicals and polymers.

Marathon Oil Company, a unit of USX Corporation, owns 30 percent of the Kenai LNG plant and the two tankers. It also operates the tankers. Marathon was founded in 1887 and has its headquarters in Houston, Texas. As a major participant in the natural gas production and processing industry, Marathon produces about 1 billion cubic feet of gas per day world wide.

Among Marathon's current gas-related interests are a number of gas plants processing about 1 billion cubic feet per day; its wholly owned Kinsale Head gas field facilities — the only commercial source of petroleum hydrocarbons in Ireland; and the Brae B gas cycling system, the first in the British sector of the North Sea and one of the largest offshore systems in the world. In addition to its natural gas interests, Marathon is engaged in:

- Petroleum exploration and production on a worldwide scale.
- Petroleum refining and marketing in the United States.

The LNG Industry and Kenai

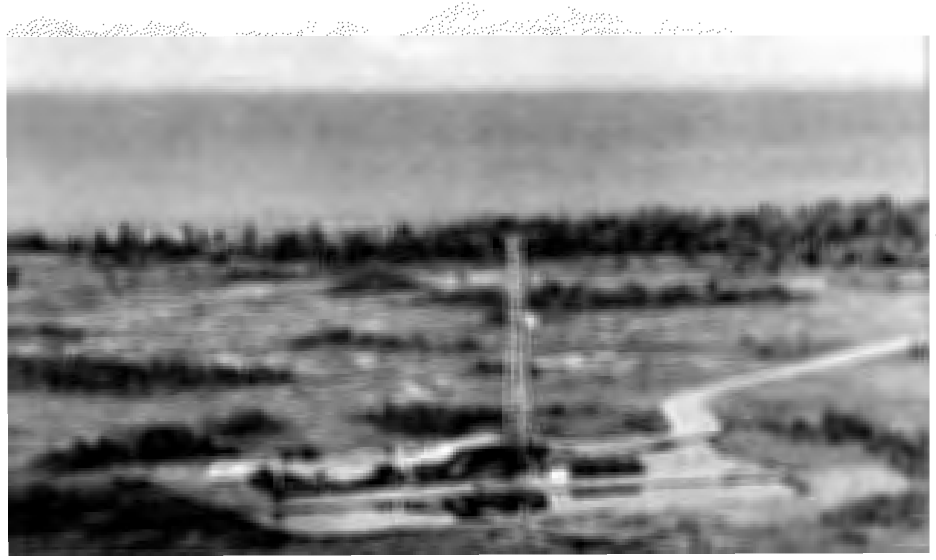
Until well into the 20th Century, natural gas was considered a nuisance and by-product of crude oil production. Marathon and Phillips were among the first companies to recognize the potential of gas. Marathon (then known as The Ohio Company) found large natural gas reserves in remote areas of Wyoming in 1915. In the early 1920s, Marathon pioneered the development of natural gas pipelines to bring the gas to market and created several natural gas subsidiaries.

In the 1920s, Phillips Petroleum founder Frank Phillips recognized natural gas as a source of valuable liquids, such as propane and butane, that can be extracted from raw natural gas for use in gasoline and other products. By 1924, Phillips was the largest producer of natural gas liquids in the United States — a position it still holds through its interest in GPM Gas Corporation. In the 1930s, Phillips developed the liquefied petroleum gas (LPG) business. LPG has provided economical fuel in rural areas for years and more recently has been recognized as an environmentally friendly motor fuel.

Based on experiments started in 1937, the first large-scale cryogenic liquefaction, or super cooling, of natural gas to create LNG began at a Cleveland, Ohio, utility in 1941. A group of American oil companies carried out the first ship transportation of LNG on an experimental basis in the late 1950s. The first large, commercial LNG trade began when Great Britain started importing LNG from Algeria in 1964. France followed suit in 1965.

The development of LNG technology coincided with the growth of the oil and gas industry in Alaska. Until the 1950s, oil companies hesitated to explore in Alaska because of the territory's distance from major markets. Marathon geologists led the search that produced the huge Swanson River oil discovery on the Kenai Peninsula in 1957. The discovery demonstrated the potential of the area and attracted many other companies.

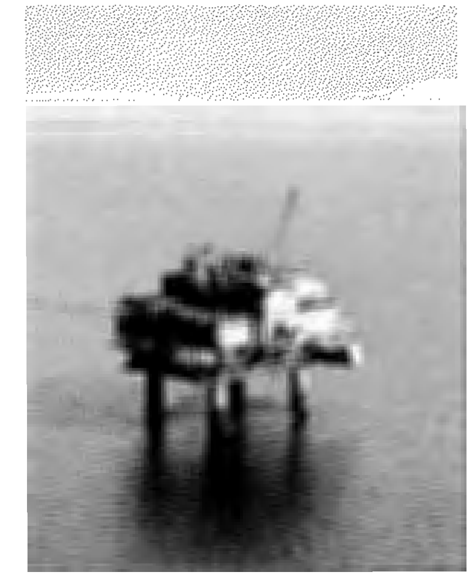
The Kenai LNG project stemmed from Marathon's 1959 discovery of the Kenai gas field and discovery of the North Cook Inlet gas field by Phillips and partner companies in 1962. Because of a lack of local, Alaskan demand for natural gas, Marathon, Phillips and other firms with gas reserves began considering international LNG projects.



At the same time, Tokyo Gas Company Ltd. and the Tokyo Electric Power Company Inc. recognized the value of LNG to help reduce Japan's air pollution problems while providing needed energy. After Phillips and Marathon offered separate proposals to the utilities, it was agreed that Phillips and Marathon jointly participate in one project. In 1967, an LNG sales agreement was signed by Phillips and Marathon as sellers and the two Tokyo utilities as buyers.

Thus began what was then the largest project of any kind in Phillips' or Marathon's histories. The project required coordinated effort involving four major areas:

- Design and construction of a liquefaction plant — including deep-water docking and loading facilities — by Phillips.
- Design and construction of the two, largest LNG tankers built until that time.
- Design and construction of the first LNG receiving and regasification facility in Japan at Negishi, south of Tokyo — the first such installation in Asia. In addition to using regasified LNG for fuel in electric power generation, the Japanese have also used the extraordinary cold of the LNG for its cryogenic value, and have constructed facilities near the LNG port for refrigeration of fresh tuna and manufacture of liquid oxygen and nitrogen.
- Additional drilling of wells in the Upper Cook Inlet and Kenai Gas Fields. This required construction and installation of an offshore platform and production facilities, an onshore gathering system, and engineering and completion of 62 miles of pipeline transportation from the gas fields to the LNG plant.



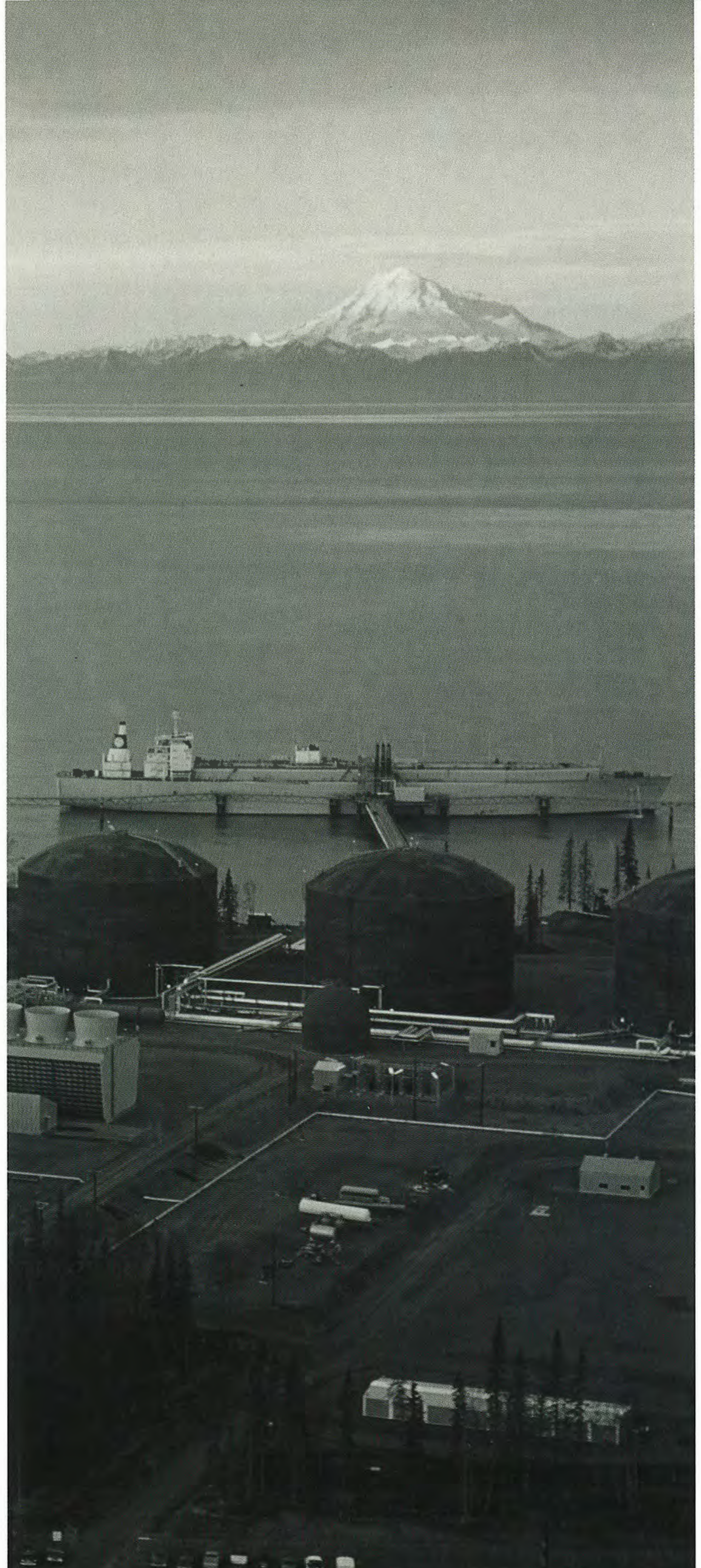
The platforms, pipelines, plant and loading facilities were built to withstand the sometimes severe environment of southern Alaska — strong winds, 30-foot tides, ice in Cook Inlet, 8-knot currents, earthquakes and winter temperatures plunging to -40° F/C. Despite the difficulty of working under these conditions, construction crews finished all work on schedule.

Fabricated in Japan and completed on location, the Tyonek production platform began operation in late 1968. While the platform was being installed, crews simultaneously laid two, 10-inch underwater pipelines to shore more than 13 miles to the east. From landfall, a 16-inch, 30-mile pipeline was constructed down the west shore of Kenai Peninsula to the LNG plant site.

Meanwhile, Marathon laid gathering pipelines and an 18-mile, 20-inch pipeline to connect onshore wells in the Kenai field.

On June 8, 1969, the plant made its first LNG exactly 26 months after the start of design and less than two years after the start of site clearing. The plant came on stream with essentially no start-up problems and operations soon exceeded expectations.

That fall, the first tanker loaded with LNG left the Kenai Plant dock. After a nine-day voyage, the vessel docked in Yokohama and discharged its cargo. This marked the first commercial LNG exported from the Western Hemisphere and the first LNG imported into Japan and Asia.



The Plant

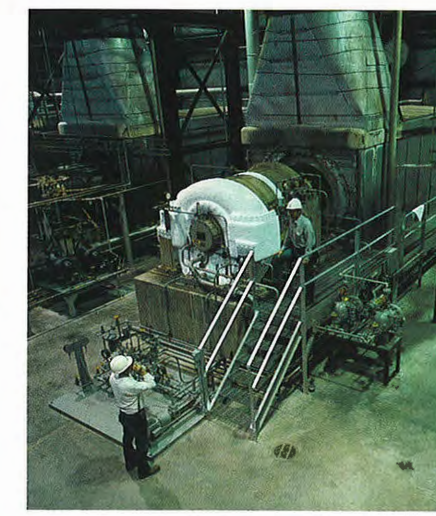
The Kenai Liquefaction Plant has been in continuous operation since 1969 on a 24-hour-a-day basis and has delivered, on average, in excess of contract quantity since its first full year of operation in 1970. Annual contract quantities are scheduled to be 68.3 trillion Btu (British thermal units) in the mid-1990s. This is enough to provide heat and power to the entire greater Tokyo area for approximately 11 days.

As one of the oldest, continuously operating LNG plants in the world, the Kenai Plant still serves as an LNG industry role model for safe, efficient and reliable operation. An assessment of the independent consulting firm, Arthur D. Little Inc., concluded the facility could safely and reliably fulfill its contract delivery quantity through 2009 — 40 years after start-up.

There are a number of reasons for the fine condition and record of the plant. The 40 employees who operate it are well trained and committed to preventive maintenance and safety. Since the beginning of operation, the plant has been maintained with a rigorous program, which includes regular inspections by company experts.

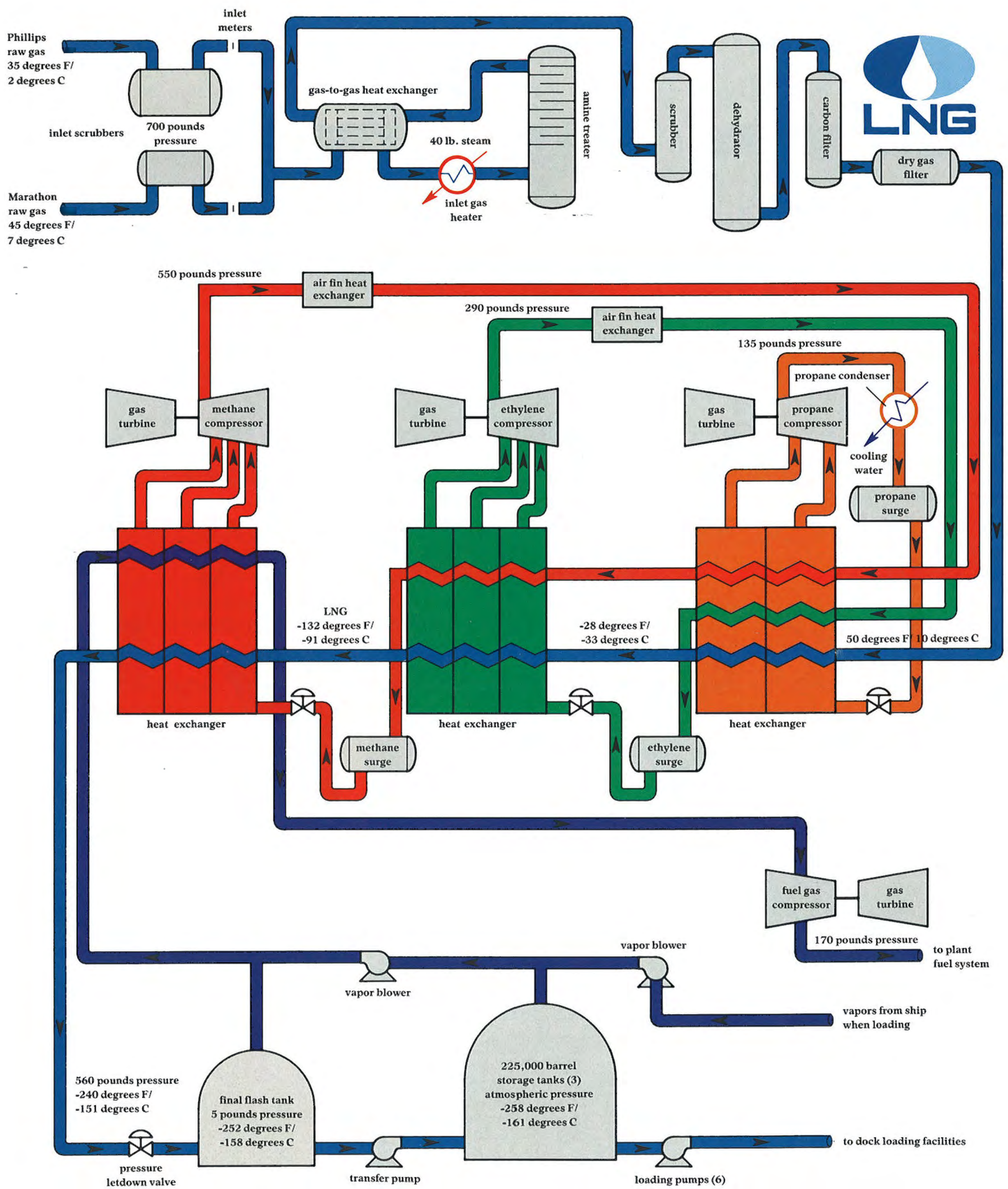
An in-depth plant review is conducted at the annual two-week plant "turnaround," or major maintenance operation, usually performed while one of the LNG tankers is in dry dock for regular inspection and maintenance.

In addition, a major project to optimize plant performance and reliability was completed in 1993.



The Kenai Peninsula's cold climate and clean, non-salty air provide an ideal operating environment for preventing corrosion of plant equipment. The raw gas — almost pure methane — is extremely low in sulfur and non-corrosive.

LNG Manufacturing Flow Diagram



The Kenai Plant Process

The process of producing liquefied natural gas is fairly complex, but can be simplified as follows:

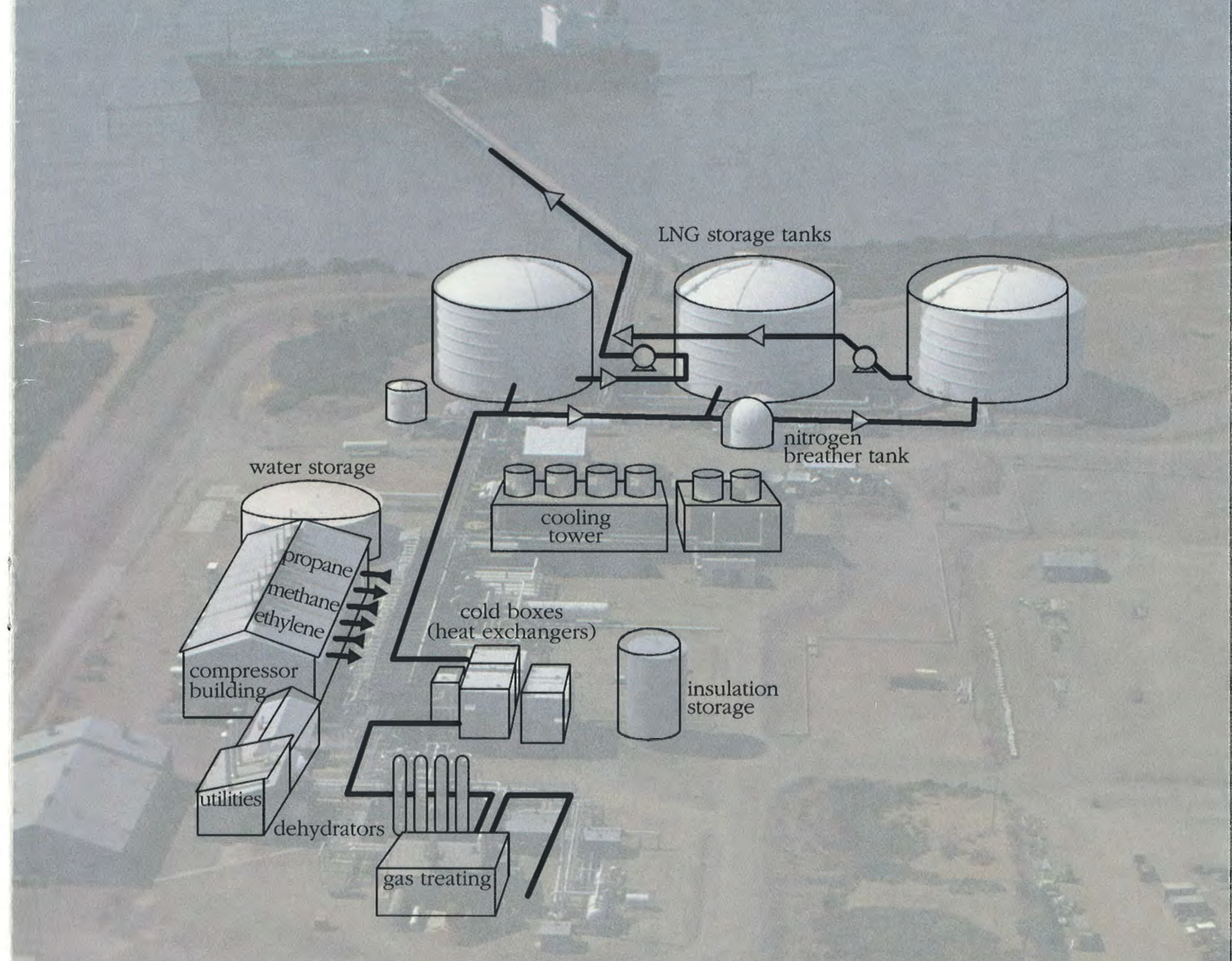
Raw gas is received as more than 99 percent methane and is processed to remove water, carbon dioxide and other impurities.

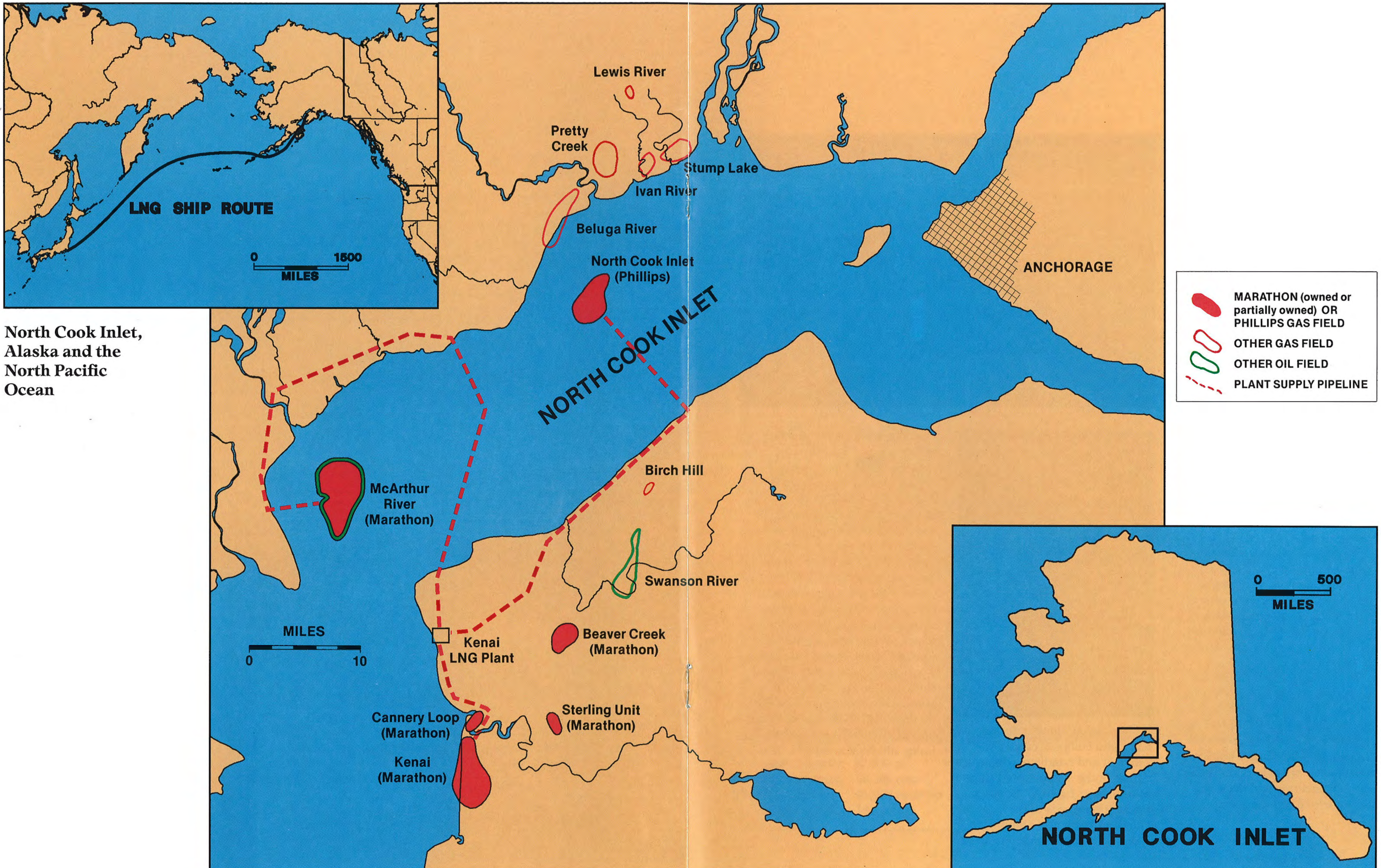
The purified gas enters the Phillips Cascade System, consisting of three chilling cycles using different refrigerants — propane, ethylene and methane — for each cycle. Each cycle reduces the temperature until the gas liquefies.

The sub-cooled liquid is then "flashed," or subjected to a reduced pressure, to produce LNG at approximately atmospheric pressure.

The LNG, now near -259° F (-161° Celsius), is transferred to three, heavily insulated, 225,000-barrel storage tanks. While in storage, some LNG "boils off," which maintains the remaining LNG at its liquid temperature. This boiloff also provides fuel for the plant's large refrigeration compressors.

The final step of the process is loading LNG on the tankers. Each ship can be loaded in 18 hours and leaves Kenai with 555,000 barrels of LNG.





North Cook Inlet, Alaska and the North Pacific Ocean

The Ships

The pioneering spirit of the Kenai LNG project continued with the introduction of two, specially designed tankers, *Polar Eagle* and *Arctic Sun*, in 1993. They replaced the *Polar Alaska* and *Arctic Tokyo*, which had provided 24 years of reliable service. The new tankers increased transport capacity by about 25 percent, compared with the earlier vessels, and are the first ships in the LNG industry to use the IHI Self-Supporting, Prismatic, Type B — or SPB — tank design.

These independent, prismatic tanks closely match the shape of the ship's hull to combine the seagoing advantages of a flat-decked ship and the cargo-carrying flexibility of rigid, self-supporting tanks.

Each ship makes 16-19 round trips a year, with each trip averaging 20 days and covering a round-trip distance of 6,600 nautical miles. Meanwhile, dock facilities in Japan were expanded and improved as the new tankers entered service.

Marathon operates the *Polar Eagle* and *Arctic Sun*, each with a crew of about 30. Phillips and Marathon jointly developed cargo handling procedures, produced operating manuals and trained the crew in operations and safety. The engineering and deck officers are well trained in the sophisticated engine room procedures and complex cargo containment and handling system.

Both of the sophisticated ships were built in Japan to the most exacting standards of the American Bureau of Shipping and have been upgraded to meet changing international shipping requirements. The ships are inspected by the U. S. Coast Guard, the Liberian government and the American Bureau of Shipping to ensure compliance with national and international standards. As a result, both are independently surveyed five or more times each year.

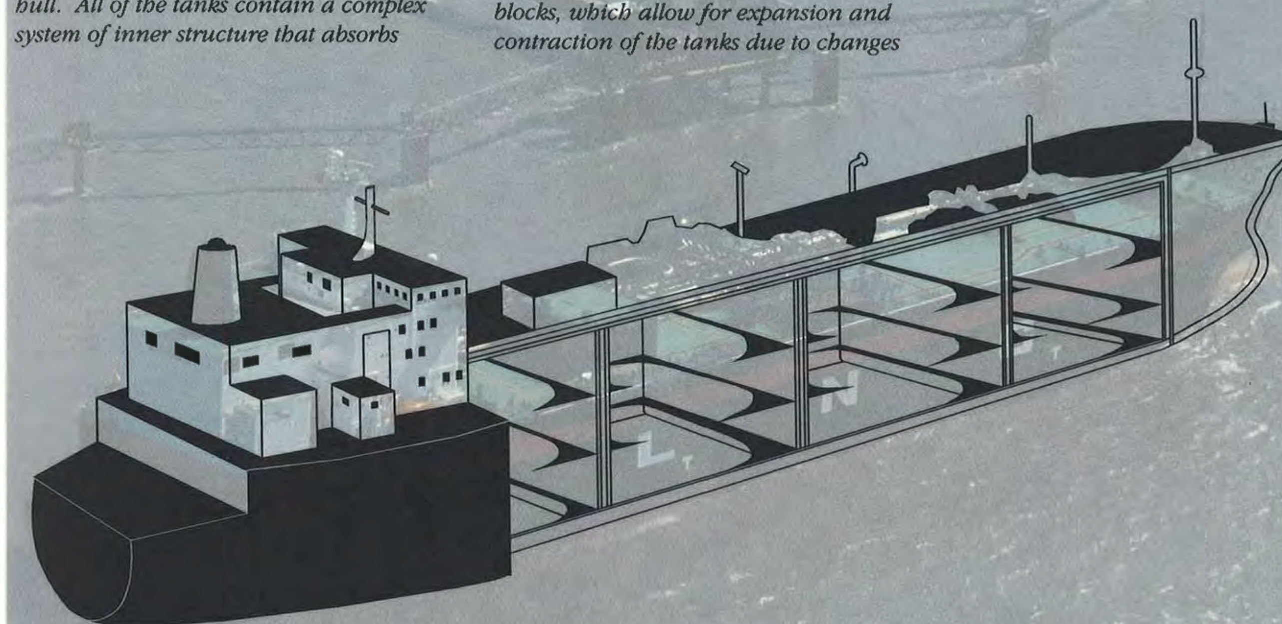
The ships are maintained and drydocked in Japanese shipyards at regular intervals in order to assure reliable and extended service life. Their propulsion system is extremely dependable. The ships' hull strength, which exceeds construction requirements for similar ships, will allow these ships to operate for many years without losing structural integrity.

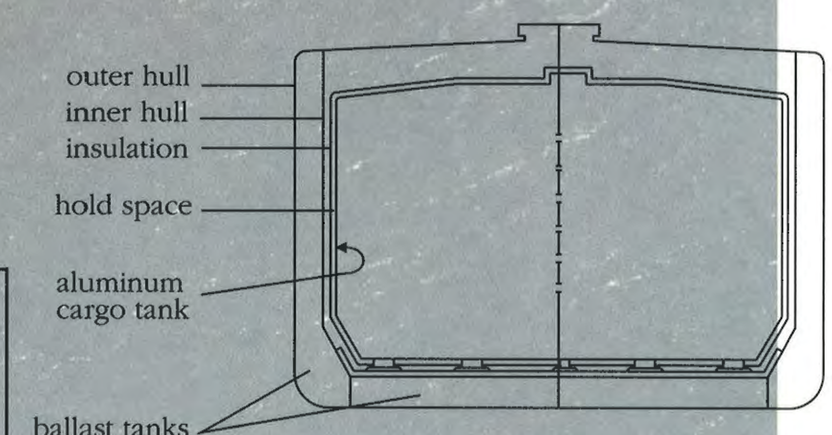
Tanker Specifications

Each ship carries liquefied natural gas in four tanks using the IHI Self-Supporting, Prismatic Tank, Type B, or SPB containment system. Each tank is constructed from heavy aluminum plate fabricated to a prismatic shape, allowing each tank to match the form of the ship's hull. All of the tanks contain a complex system of inner structure that absorbs stress fluctuations resulting from wind, wave, cargo load and temperature changes. A longitudinal and lateral "swash" bulkhead is integrated into the structure of each tank to help prevent sloshing of the LNG, especially while the ship is in a partially loaded condition.

The tanks are supported in the ship's hull using a matrix of laminated wooden blocks, which allow for expansion and contraction of the tanks due to changes in temperature. Insulation, to limit evaporation of the LNG, is 300 mm (11¾ inches) of polyurethane.

Evaporation, or "boiloff," is collected, compressed and used as fuel in the ship propulsion system. Fuel requirements in excess of this natural "boiloff" can be supplied by fuel oil or by forced vaporizing of the LNG cargo.





Midship Section

LNG Ship Particulars

Length	239 m	784 ft
Breadth	40 m	131 ft
Depth	27 m	88 1/2 ft
Draft loaded	10.1 m	33 ft
Cargo capacity	87,500 m^3	555,000 bbls.
Gross tonnage	66,300 tons	
Steam turbine	21,000 shaft hp	
Service speed	18.5 knots	


L N G

The Customers

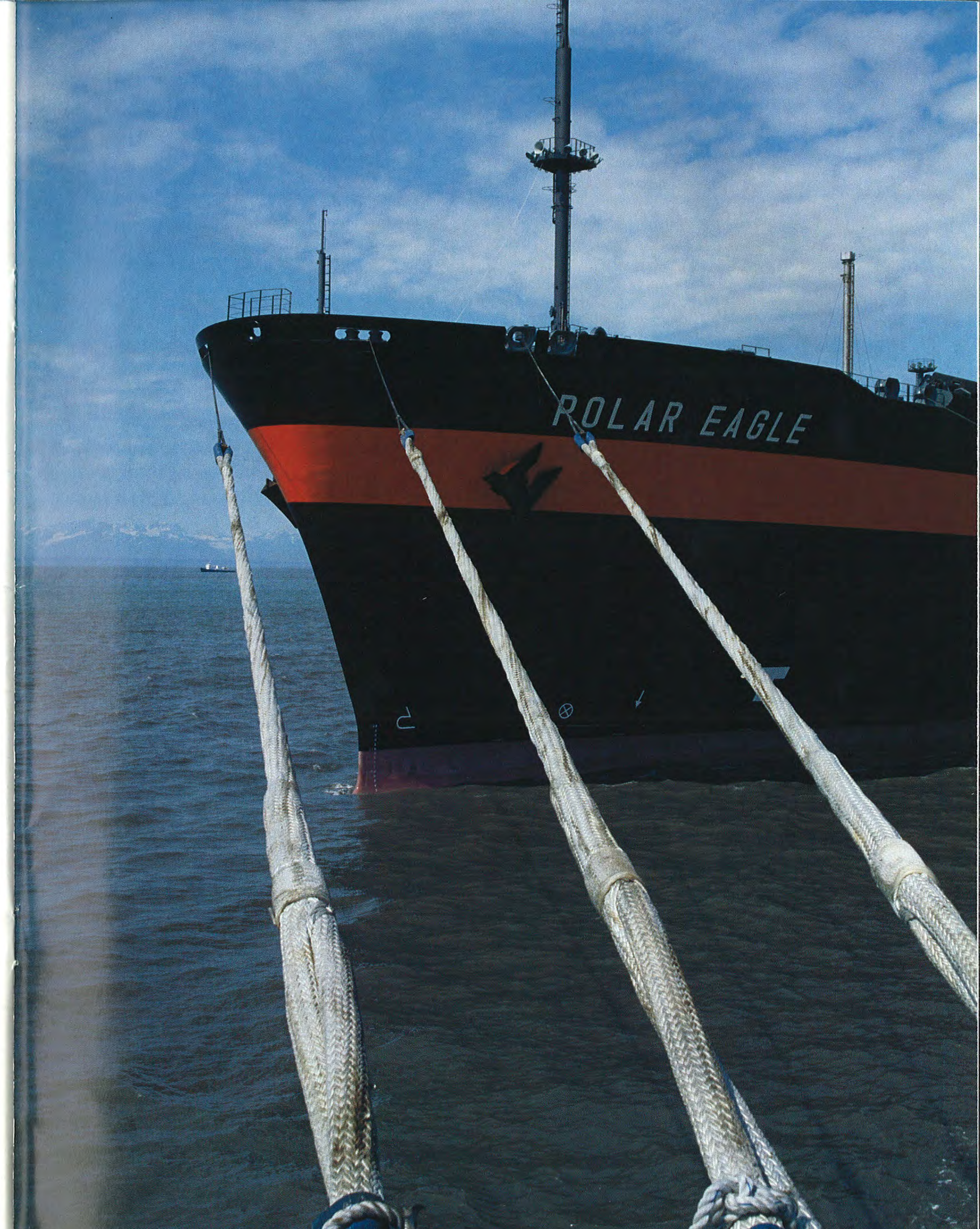
The Tokyo Electric Power Company Inc. (TEPCO) is the largest electric utility in Japan and the largest privately owned electric power company in the world. The company supplies electricity to about 20 million customers in the Greater Tokyo area. To assure a reliable supply of electricity and to reduce air pollution, the company has diversified its fuels base, emphasizing clean-burning LNG and liquefied petroleum gas for 32 percent of its power.

TEPCO

The rest of the TEPCO fuel base includes nuclear power, oil, hydroelectric power and coal. The company is the world's largest user of LNG and consumes 75 percent of the output from Kenai. In addition to Alaska, the company imports LNG from Abu Dhabi, Brunei, Malaysia, Indonesia and Australia. In the early 1990s TEPCO had assets in excess of $106 billion.

Tokyo Gas Company Ltd. is Japan's largest gas utility, providing gas to about 7 million customers in the Greater Tokyo area. Tokyo Gas is the largest of the nation's 250 gas companies with almost 40 percent of the market. Approximately 87 percent of Tokyo Gas's supplies are derived from LNG. Tokyo Gas began its research into the use of LNG in 1957. The company consumes 25 percent of the Kenai plant's output. Tokyo Gas also imports LNG from Brunei, Malaysia and Australia. In the early 1990s Tokyo Gas had assets in excess of $9.9 billion.

TOKYO GAS

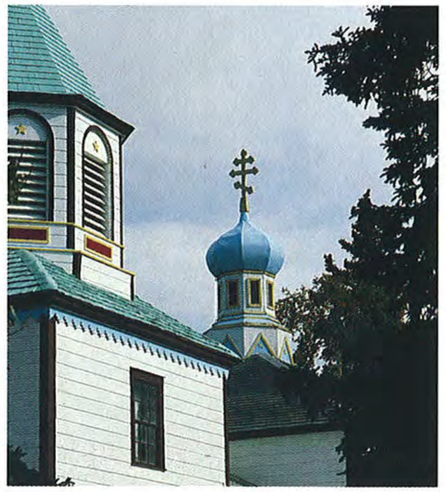


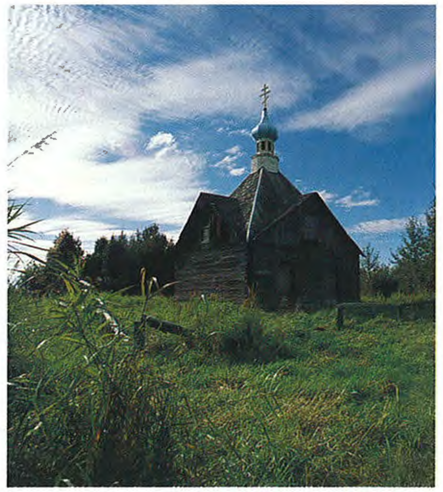
The Kenai Area

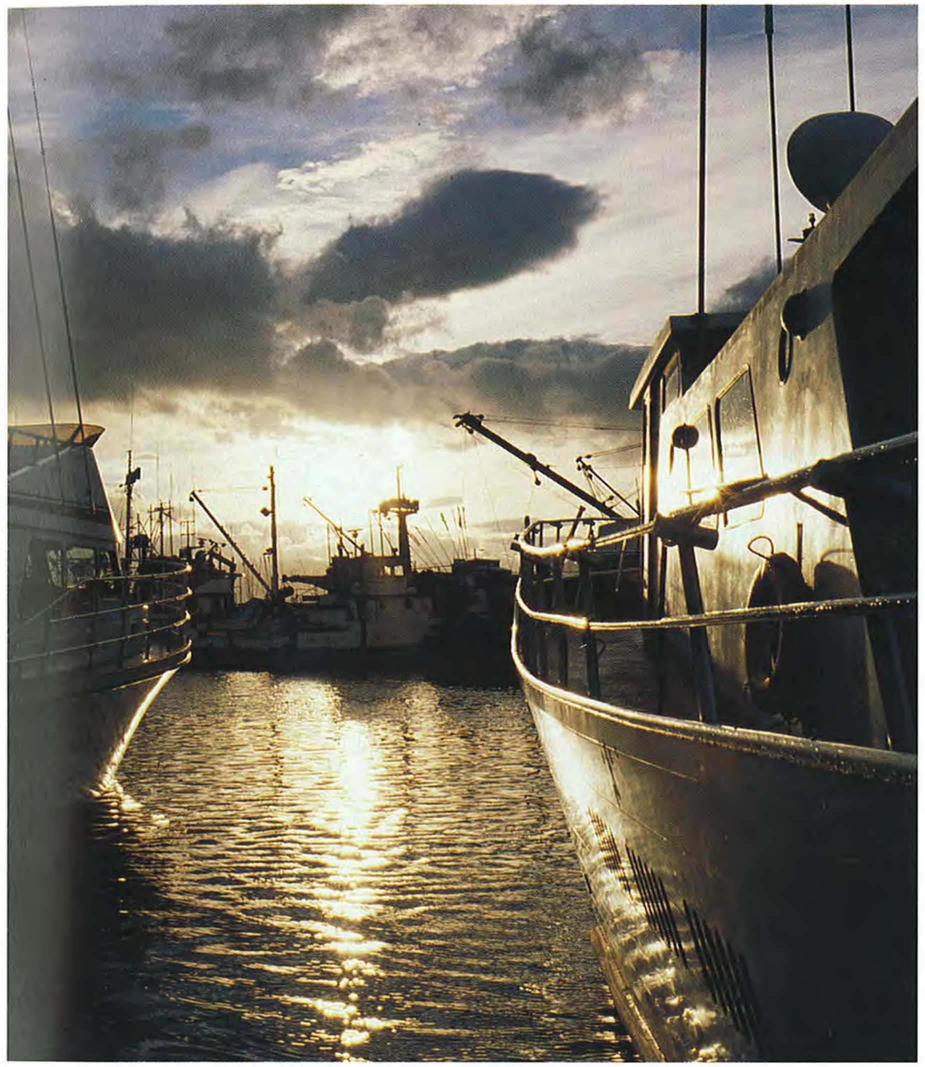
Alaska is at its best on the Kenai Peninsula. The setting features the beauty of Cook Inlet combined with the majesty of the Aleutian Mountain Range, dominated by the active volcano Mount Redoubt. Among the abundant wildlife are moose, brown bear, caribou and bald eagles. White beluga whales enter Cook Inlet to feed in the summer.

The area's original occupants were the Tanaina Athabascan Indians. In 1791, Russian fur traders established Fort St. Nicholas at the mouth of the Kenai River. After Alaska was purchased by the United States from Russia in 1867, the American military briefly established an outpost at the site. The heritage of Russia can still be seen in three Kenai structures; Holy Assumption Church, built in 1895-96; St. Nicholas chapel, built in 1906; and the Orthodox Church rectory, built around 1886.

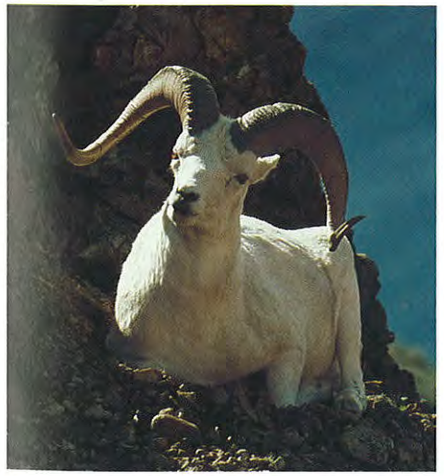
In addition to being a focal point for oil and gas, the peninsula is a key part of another industry — fishing. Commercial fleets are active in the summer and vacationers come from around the world to fish the Kenai River for king salmon. Many varieties of salmon spawn in other area rivers also.







The Kenai LNG plant is at Nikiski, once a Russian fishing village. The site is the northernmost Cook Inlet port open all year and was chosen because it is close to the gas fields supplying the plant. Anchorage, Alaska's largest city, is 165 miles away by road, 60 miles by air, and home for more than 250,000 people — about half the state's population. Kenai, located 10 miles south of Nikiski, has a population of 6,500 and is the largest city on the peninsula.

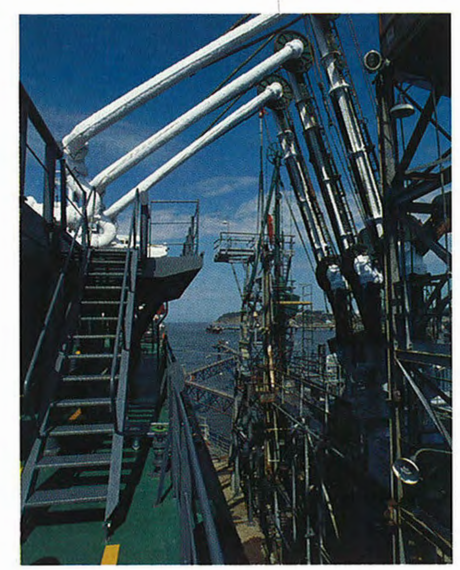


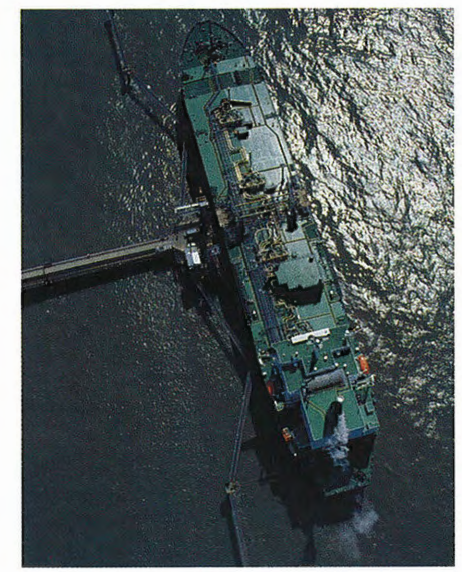
The Future

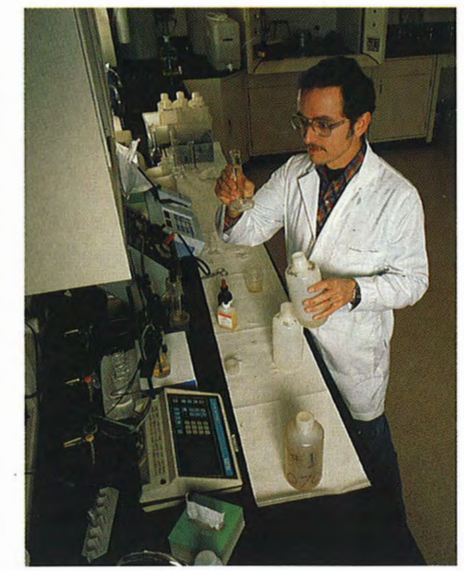
Phillips and Marathon have sufficient uncommitted, proven gas reserves to meet contract requirements. In addition, the Cook Inlet Basin is still rich in hydrocarbons. In the early 1990s — after 25 years and 3 trillion cubic feet of production — the U.S. Geological Survey estimated an additional 5 trillion cubic feet of gas in Cook Inlet was economically recoverable. In fact, Phillips participated in a new, major hydrocarbon discovery in Cook Inlet in 1992. As demand for natural gas increases, exploration will continue.

Because the United States already has sufficient gas supplies into the 21st century according to the American Gas Association, the increases in natural gas demand will likely be on the Pacific Rim. Japan, which depends on imports to satisfy some 90 percent of its energy requirements, is expected to increase its LNG consumption into the next century. In addition, Taiwan and Korea have expanding energy markets.

Clean, versatile and high in caloric efficiency, LNG is an ideal product to satisfy growing energy demand, to build better trade relations, and to benefit the overall development of the Pacific region.





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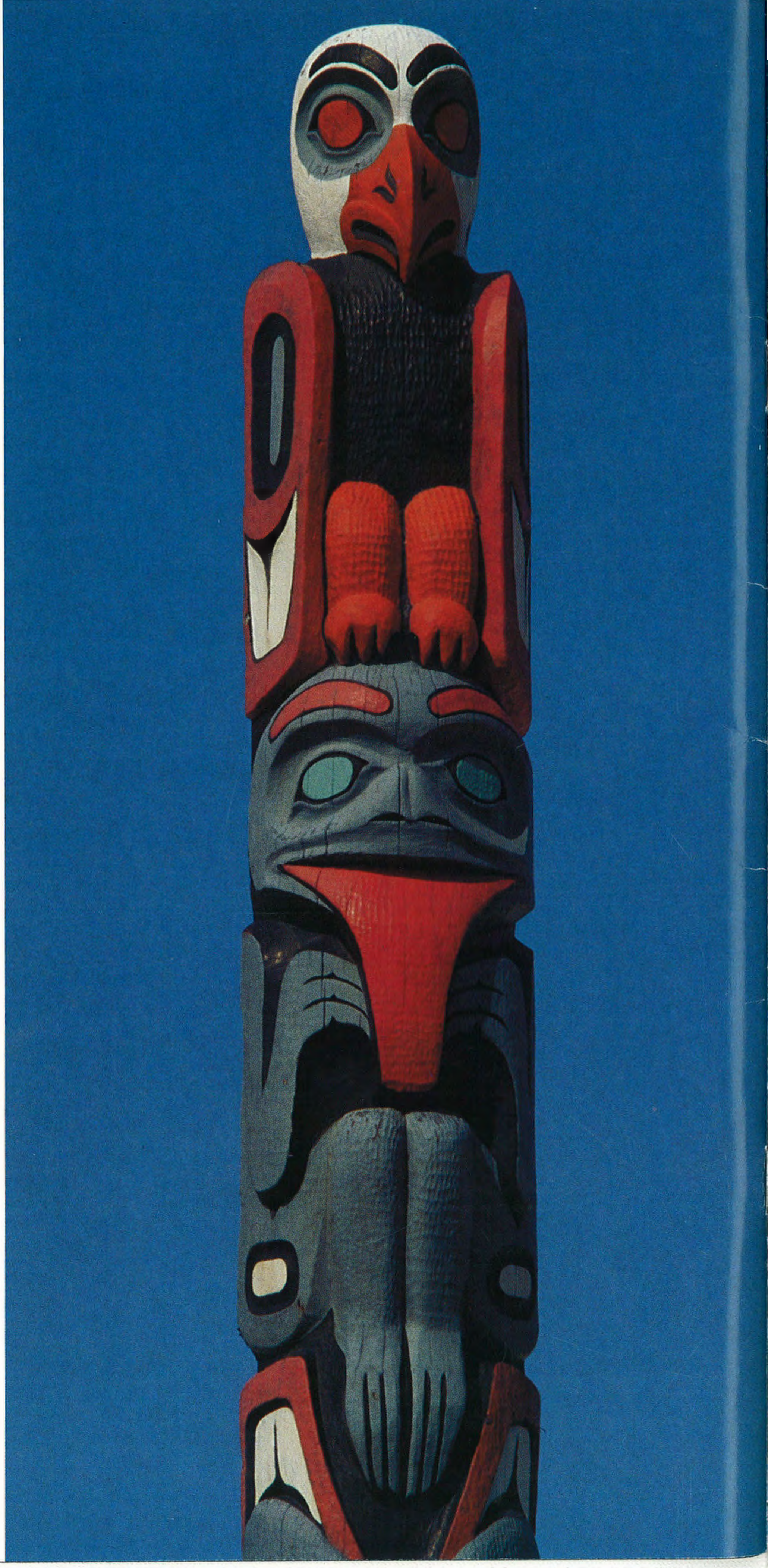
L N G

Phillips and Marathon welcome your comments about Kenai LNG operations or other aspects of their business. Write to one of the addresses below:

Phillips Alaska
Natural Gas Corporation
Post Office Box 1967
Houston, Texas 77251

Marathon Oil Company
Post Office Box 3128
Houston, Texas 77253



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