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AKLNG PROJECT—LAZARD INTERIM REPORT

LAZARD

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I Introduction

I. Introduction

The State, pursuant to Senate Bill 138 ("SB 138"), has engaged Lazard to provide assistance in reviewing and analyzing various financing options for the State's interest in the Alaska LNG Project (the "Project" or "AKLNG Project"). This Interim Report provides a detailed description of the Project, an overview of the State's finances and an introduction to various financing considerations for the Project in advance of the Final Report, to be delivered in Fall 2015,[1] which will provide a detailed description of a range of financing alternatives, analyze the benefits and considerations of these alternatives and deliver specific financing recommendations to the State.

A. Legislative Origins of Lazard AKLNG Report

SB 138, signed into law on May 8, 2014, calls for the "development of a plan" for Alaska "municipalities, regional corporations and residents to participate in the ownership of a North Slope natural gas pipeline."[2] Pursuant to this legislation, the Alaska Department of Revenue Commissioner's Office solicited proposals from qualified firms to serve as a "financial consultant on the State's participation in the continued development of a liquefied natural gas project from Alaska's North Slope." The goals of the engagement were to include "the identification of financing options for State ownership and participation in a North Slope natural gas project, [a] description of the risks associated with each option and the effect of each option on the State's debt capacity and the State's long-term debt rating" as well as "recommendations as to how to allow municipalities, regional corporations and individuals of the State an opportunity to participate as a co-owner in the project."[3] At the conclusion of the RFP process, the State selected Lazard to serve as its financial consultant.

1 Prior to any Front-End Engineering and Design ("FEED") decision.
2 SB 138 Sec. 76(a) – (c).
3 State of Alaska Department of Revenue, Request for Proposal ("RFP") 2015-0400-2600: AKLNG Financial Consultant.

B. Role of Lazard

As a financial consultant, Lazard will analyze[4] and report on potential financing alternatives for State participation in the AKLNG Project (including potential direct participation on behalf of residents, municipalities and/or regional corporations). As part of its mandate, Lazard will:

- Formulate a range of potential financing alternatives and evaluative criteria
  - Analyze, for example, the key potential risks, potential impact on the State's debt capacity and long-term debt rating, potential for participation of various Alaska stakeholders and tax implications associated with each alternative
- Collaborate with stakeholders, including the State, Alaska Gasline Development Corporation ("AGDC"), ExxonMobil ("Exxon"), ConocoPhillips ("Conoco"), BP, TransCanada Corporation ("TransCanada"), State advisors and other constituents
- Develop specific recommendations designed to maximize benefits to the State
- Meet Project deliverable requirements:
  - Delivery of Interim Report by January 20, 2015
  - Delivery of Final Report in Fall 2015[5]

4 In coordination with the State Department of Revenue and other State advisors, including FirstSouthwest, Black & Veatch and Greenberg Traurig.

5 Prior to any FEED decision.

II Executive Summary

II. Executive Summary

EXECUTIVE SUMMARY

LNG BACKGROUND AND OVERVIEW

GLOBAL LNG OVERVIEW

- Global market dynamics seemingly support the development of new liquefied natural gas ("LNG") export projects[6]
  - Over the past 20 years, LNG has become a significant global energy source with trade volumes that have more than quadrupled over that period
  - LNG demand is highly concentrated in Pacific Rim countries and is expected by industry experts to increase in the coming years, particularly in China, Japan and Indonesia, where the greatest number of new LNG receiving terminals are being developed
- The global LNG market involves an ecosystem of participants, including governments, producers, construction companies, shippers and operators, among others

OVERVIEW OF ALASKA'S NATURAL RESOURCES AND LNG POSITIONING

- Significant natural gas resources exist in Alaska, particularly in the North Slope region
  - Since the 1970s, numerous stakeholders, including State and Federal government administrations, and private sector entities, have attempted, without success, to develop these natural gas resources in Alaska's North Slope
- The supply of North Slope natural gas potentially represents a valuable investment opportunity for the State and its residents
  - In-State natural gas development could potentially support Alaska's budget, particularly in the coming years, when oil production is expected to decline
  - Alaska's natural gas resources are significant and could potentially support the State's position as a top-five global LNG exporter
- Alaska holds certain advantages in the development of a large-scale LNG project, including:
  - A highly stable political environment as compared to countries that are the site of large-scale development projects (e.g., Nigeria, Russia, etc.)
  - Colder temperatures, which make the liquefaction process more efficient
  - Higher heat content natural gas, which makes the commodity more valuable
  - Access to Pacific Rim LNG markets, which constitute the majority of existing LNG demand and projected demand growth

AKLNG PROJECT OVERVIEW

- The Project involves the coordinated efforts of oil producers Exxon, BP and Conoco, together with TransCanada and the State
  - In addition, a number of Alaska entities and constituents may participate in or stand to benefit from the Project, including State residents, Alaska municipalities, Alaska native corporations and various other Alaska entities
- The Project primarily consists of three components: a gas treatment plant ("GTP"), a gas pipeline ("Pipeline") and a liquefaction plant ("LNG Plant")
  - The State has entered into an agreement with TransCanada to help finance the State's portion of the GTP and the Pipeline
- Project sponsors include Exxon, BP, Conoco and the State, each with a currently contemplated 25% ownership stake[7]

6 Current commodity pricing environment (including historically-low oil prices) has the potential to negatively impact LNG project development. In preparation for the delivery of the Final Report in Fall 2015, Lazard will continue to monitor global LNG market dynamics.

7 25% ownership figure is illustrative. Ultimate Project ownership percentage will depend, for example, on each entity's share of Project gas, among other factors, and may vary from this amount.

AKLNG PROJECT OVERVIEW (CONT'D)	■ Currently in its Pre-FEED phase, the Project would involve approximately 2 – 4 years of additional planning followed by 5 – 6 years of construction
	  ■ The final investment decision ("FID") for the Project is estimated to occur in 2018/2019 (the vast majority of the capital investment would occur after that point)
	■ Current estimated Project cost: $45 – $65 billion[8]
	  ■ Pre-FEED: $400 – $500 million
	  ■ FEED: $1.5 – $2.1 billion
	  ■ Engineering, Procurement and Construction ("EPC"): $43.2 – $62.3 billion

STATE OF ALASKA FINANCIAL OVERVIEW	■ The State's present-day reliance on oil revenues, combined with historically-low oil prices and declining oil production forecasts, suggest that a new revenue source could help Alaska maintain its strong financial position[9]
	  ■ In FY 2014, oil revenues accounted for 88% of the State's unrestricted revenue (i.e., revenue used to fund the State's general expenses)
	  ■ At its peak, Alaska's North Slope oil production constituted 26% of total U.S. production; however, production has declined consistently since the 1980s and is projected by the State to decrease materially over the next 10 years due to diminished oil reserves
	  ■ Historically-low oil prices are placing further pressure on the State's budget
	  ■ Current forecasts show the State depleting its $15 billion budget reserve funds by 2022 – 2023
	■ In addition to revenues generated by oil production activity in the State, Alaska's financial health depends upon the performance of the State's various investment funds (e.g., Permanent Fund, etc.)
	■ In light of the State's current debt levels, and other factors, the State enjoys a "triple-A" rating from all three major credit rating agencies; however, additional capacity to issue debt may exist, subject to potential ratings agency downgrades[10]
	  ■ State maintains current "Aaa" rating: $2.7 billion of incremental debt capacity
	  ■ State is downgraded to "Aa1" rating: $4.7 billion of incremental debt capacity
	  ■ State is downgraded to "Aa2" rating: $5.9 billion of incremental debt capacity

SUMMARY PRELIMINARY FINANCING CONSIDERATIONS	■ The State should consider a variety of factors as it evaluates how to finance its portion of the Project, including the size of investment, the source of funds, the debt/equity capitalization relationship, how it structures its investment in the Project and the specific terms and conditions of the overall investment arrangement
	  ■ The size of the State's Project investment requirement depends on the participation of TransCanada as a partner, the effects of further developments with the Project and the outcome of future negotiations
	  ■ The State has a variety of sources potentially available to fund its portion of the upfront investment in the Project, including funds from the State (e.g., Permanent Fund earnings, via allocation by the Legislature), Alaska municipalities/regional corporations and residents, and external sources
	  ■ In addition to evaluating potential funding sources, the State will need to evaluate the optimal financing structure and terms/conditions under which those funds could be invested in the Project; in general, the State could structure Project investments as debt, equity or a combination thereof

8 Here and throughout this Report, Project costs are shown in 2012 dollars, unless otherwise noted. Alaska's portion of the estimated Project cost is currently projected to range from $7.0 to $13.7 billion and is subject to change, depending on further negotiation.

9 As noted herein, sustained low oil prices also, on balance, negatively impact LNG and its position in the global energy markets where LNG is competing with oil.

10 FirstSouthwest analysis.

OVERVIEW OF POTENTIAL STRUCTURING ALTERNATIVES	**STATE PROJECT COMPANY**	■ The State Project Company, a hypothetical financing vehicle for the Project, would be the entity to invest in the Project, receive Project revenues, service Project-related debt payments, etc.[11] ■ Investments in the State Project Company from various funding sources may be structured, broadly speaking, as debt, equity or a combination thereof
	DEBT	■ Recourse Debt ▪ Debt that has full recourse to the State and potentially significant impact on the State's credit rating ▪ Relatively less expensive than other debt alternatives ▪ Allows the State to maintain its undiluted ownership of and control interest in the State Project Company ■ Limited-recourse Debt ▪ Debt that has only limited recourse to the State and potentially moderate impact on the State's credit rating ▪ "Middle of the road" in terms of cost vs. other debt alternatives; still less expensive than equity alternatives ▪ Allows the State to maintain its undiluted ownership of and control interest in the State Project Company ■ Non-recourse Debt (e.g., project financing) ▪ Debt that has no recourse to the State and potentially minimal impact on the State's credit rating ▪ More expensive than other "straight" debt alternatives; less expensive than equity alternatives ▪ Allows the State to maintain its undiluted ownership of and control interest in the State Project Company ■ Hybrid Securities (e.g., Convertible Debt) ▪ A type of security that blends the characteristics of debt and equity, thereby producing a more expensive financing choice than other debt alternatives, but a less expensive financing choice than equity alternatives ▪ Well-developed area of the capital markets, but more complex than other financing alternatives; in some cases, market for investors can be relatively limited
	EQUITY	■ Common Equity ▪ Represents basic ownership interest in the State Project Company ▪ More expensive than debt alternatives; however, may facilitate optimal capital structure and structuring approaches, which could minimize control and other effects of equity issuances ▪ The sale of equity to third parties could result in the dilution of the State's ownership in and control of the State Project Company ■ Preferred Equity ▪ Debt-like equity security that would allow the State Project Company to structure its financing in a way that likely does not impact the State's credit rating ▪ More expensive than debt alternatives; however, preferred stock is less expensive than common equity and potentially preserves for the State operational flexibility and control/governance rights ▪ Allows the State to maintain its undiluted ownership in and control of the State Project Company ■ Warrants ▪ Allow the State Project Company to raise some level of capital while deferring any of the potential ownership/control dilution associated with common equity ▪ Potentially preferable to common equity, depending on exercise price, scope and benefits to other financing efforts

[11] A more detailed description of the State Project Company, and other related matters, is presented below in Section VII.

PRELIMINARY SELECTED EVALUATIVE CRITERIA

- Lazard's Final Report will provide specific analysis and recommendations with respect to the various funding sources and financing alternatives,[12] taking into account a number of key evaluative criteria, including the following:
  - Potential impact on the State's debt capacity/opportunity cost
    - The State has a finite capacity to issue debt, and to the extent that it wishes to issue debt for other purposes, this capacity may be limited depending on how much debt is issued for the Project
    - The State's funds (e.g., the Permanent Fund) invest in a variety of different securities; diverting dollars to invest in the Project means that these dollars are not available for other fund investments
  - Potential impact on the State's credit rating
    - Increasing the amount of State debt could result in rating agency downgrades
    - A decrease in the State's credit rating could constrain future efforts by the State to access the capital markets and could raise the State's overall cost of debt
  - Key risks
    - Potential for default, financial distress and loss of operational flexibility for debt structuring alternatives
    - Potential for the State to lose all or a portion of its investment in the Project
    - Potential for lenders to have recourse to State assets
  - Cost
    - Interest rate for funding alternatives and debt structuring
    - Required return for funding alternatives and equity structuring
    - Issuance, structuring and other fees (e.g., payments to underwriters, lawyers, financial advisors, etc.)
  - Execution flexibility/feasibility
    - Certain types of financing structures are easier to implement than others, including with respect to facilitating investment participation by State residents, corporations and municipalities
    - Certain types of funding sources are more accessible than others
    - Certain provisions (e.g., debt covenants) can potentially be restrictive and limit the State's flexibility
  - Alignment of interests among key parties
    - Certain financing alternatives and/or funding sources may introduce Project misalignment, conflicts of interest or other forms of dysfunction for sponsors

RECOMMENDED NEXT STEPS

In preparation for the delivery of the Final Report in Fall 2015, Lazard will focus on the following areas of analysis and interaction, among others:

- Participation in State legislative session during Spring 2015
- Continued monitoring of global LNG market dynamics
  - Update of Black & Veatch Model to reflect, among other items, current commodity pricing environment[13]
- Continued monitoring of Project developments (e.g., offtake agreements, partnership agreement, etc.) and potential impacts on analysis of financing alternatives

[12] Inclusive of any potential terms and conditions.

[13] Black & Veatch Cash Flows Model ("Black & Veatch Model"), dated February 2014, contains forecasts of Project cash flows analyzed herein.

RECOMMENDED NEXT STEPS (CONT'D)	▪ Further analysis of potential sources of funds
	  ▪ Interaction with various State and external fund providers to gauge interest in Project participation
	  ▪ Identification of preferred sources of funds via analysis and interaction with key stakeholders, including the Alaska Legislature
	▪ Further analysis of potential structuring alternatives
	  ▪ Identification of preferred structuring alternatives via analysis and interaction with key stakeholders, including the Alaska Legislature
	▪ Further refinement of evaluative criteria
	▪ Formation of potential financing alternatives (i.e., combinations of sources of funds and structuring alternatives)
	▪ Analysis of implementation issues associated with potential financing alternatives
	  ▪ Legislative
	  ▪ Regulatory
	  ▪ Legal
	  ▪ Execution
	  ▪ Other
	▪ Assessment of financing alternatives against evaluative criteria
	▪ Identification of optimal financing alternatives via iterative process (i.e., in consideration of evaluative criteria, implementation issues and other factors)
	▪ Drafting of Final Report
	  ▪ Continued iteration and interaction with the Department of Revenue and State advisors

III LNG Background and Overview

III. LNG Background and Overview

The AKLNG Project results from a long history of efforts to develop Alaska's natural gas resources. Since the 1970s, State and Federal administrations, as well as various private sector stakeholders, have attempted to monetize North Slope natural gas reserves without success. However, the global LNG market has evolved considerably since those early efforts. The current AKLNG Project benefits from strong global LNG demand dynamics, competitive geographic advantages, alignment of interests among key Project stakeholders and a more advanced understanding of the costs and benefits associated with the Project.

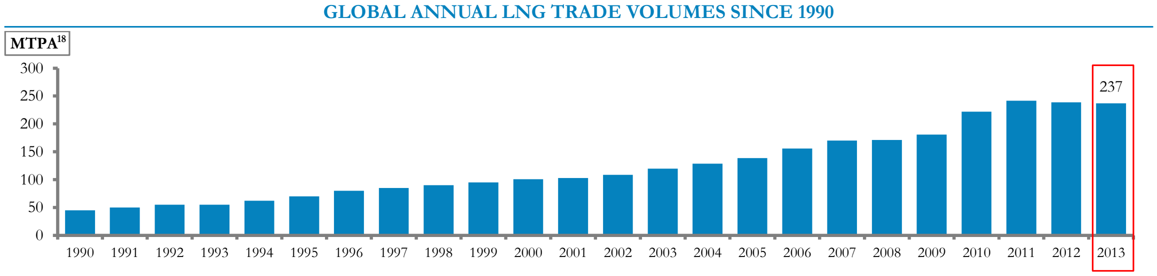
A. Global LNG Overview

1. LNG Market Overview

LNG is a form of natural gas that has been condensed via extreme cooling. Unlike oil, natural gas is not liquid at room temperature, and must be cooled to allow for cost-effective shipment, via a process known as liquefaction. Once cooled (at -259°F or below), natural gas is 600 times denser than it is at ambient temperatures, allowing for shipment over long distances, and enabling delivery to distant geographies.[14]

Over the past twenty years, LNG has transformed from a regional energy source to one with worldwide economic and political implications. Various factors have affected the surge in demand for LNG, including both political and market forces. For example, increasing concern around the environmental impact of traditional energy sources has prompted attention to natural gas as the cleanest-burning fossil fuel (it produces 60% – 90% less hydrocarbon emissions than oil).[15] Certain markets and electricity providers that have sought methods to minimize the impacts of supply/demand volatility have found that the long-term fixed contract model of LNG provides a logical solution.[16] In other markets, where remote geography and/or a lack of natural resources constrain the supply of energy assets, LNG has proved to be a cost-effective energy source.[17] The role of LNG in the global marketplace has steadily increased since 1990, as illustrated in the chart below.

GLOBAL ANNUAL LNG TRADE VOLUMES SINCE 1990

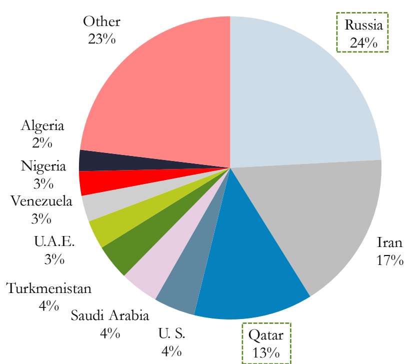


Source: IGU World LNG Report.

14 "Fall 2013 Revenue Sources Book," The State of Alaska, 2013 ("Fall 2013 Revenue Sources Book").
15 "LNG – Global Challenges & Opportunities and Imperatives in India," The Boston Consulting Group, 2014 ("BCG Report").
16 "Global LNG," EY, 2014 ("EY Report").
17 "World LNG Report," International Gas Union, 2014 ("IGU World LNG Report").
18 Metric tons per annum ("MTPA").

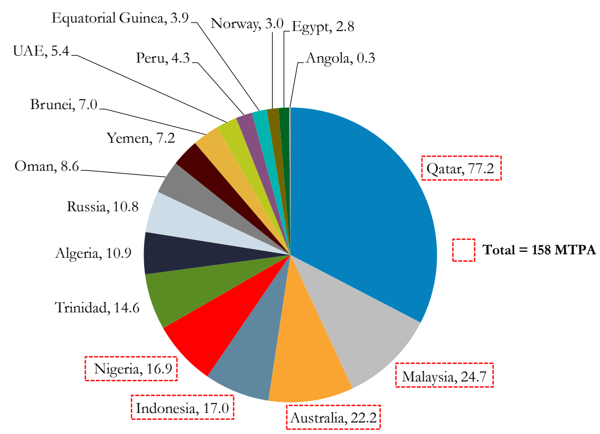
Global LNG supply is highly concentrated, with the top five producing countries providing 67% of the total global supply of 237 MTPA.[19] Both supply and demand dimensions shape this high concentration. While countries with plentiful natural gas reserves typically produce greater LNG exports, this is not always the case, as a result of several factors. For example, high fixed costs associated with upstream development and liquefaction can inhibit development. Also, some countries rich in natural gas reserves, such as the U.S. and Russia, have significant domestic demand, which limits exports.[20] This relationship is illustrated in the charts below; while Russia has the largest global proved reserves of natural gas at 24% of the total, it accounted for only 5% of global LNG exports in 2013. Conversely, while Qatar accounts for only 13% of global proved reserves, it produced the largest share of global LNG exports in 2013 at 33% of the total.

2013 NATURAL GAS PROVED RESERVES BY COUNTRY (Tcf[21])



Total Proved Reserves: 6,991 Tcf
Source: U.S. Energy Information Administration ("EIA").

2013 LNG EXPORTS BY COUNTRY (MTPA)



Total LNG Exports: 237 MTPA
Source: IGU World LNG Report.

Today's LNG supply landscape is still dominated by the first movers in natural gas liquefaction. Qatar now controls a significant share of global LNG production, largely as a result of a rapid series of developments in the mid-2000s,[22] but other top exporting countries have been significant players in LNG for several decades. Indonesia began exporting LNG in the mid-1970s,[23] and Malaysia and Australia emerged as major exporters in the 1980s.[24] Existing suppliers continue to increase capacity, however, and the supply landscape is expected to diversify over the next decade as many other nations and geographies (e.g., Venezuela, North Africa, etc.) increase their capacity despite

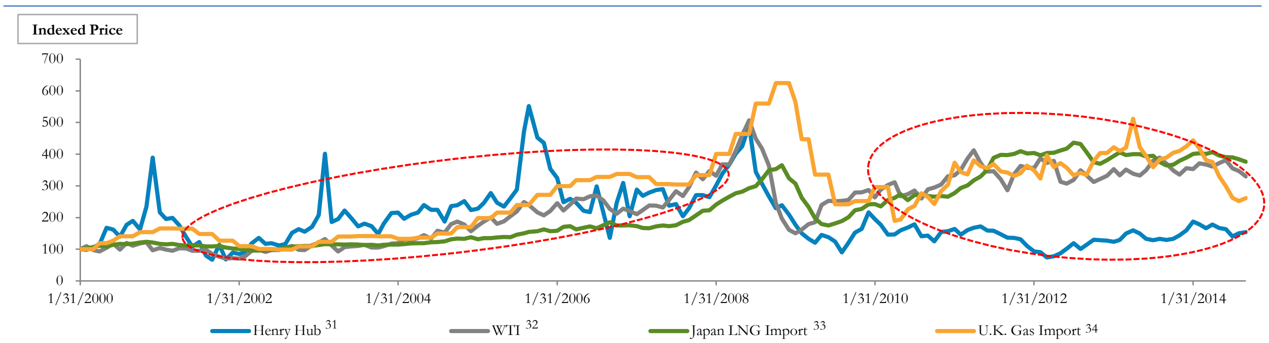
19 Based on 2013 figures.
20 "An Overview of the World LNG Market and Canada's Potential for Exports of LNG," Canadian Association of Petroleum Producers, 2014.
21 Trillion cubic feet ("Tcf").
22 EY Report.
23 "Significant Events in the History of LNG," Energy.gov, 2004.
24 "Fifty Years of Global LNG," Trafigura, 2014.

significant geopolitical and financial barriers. As a result of this increase in LNG supply, LNG is expected to constitute a larger proportion of total natural gas production going forward.[25]

Global LNG demand is also highly concentrated, with Asian markets—particularly Japan, South Korea and China—being the largest importers. The reliance of these countries on LNG is driven by factors such as remote geography, lack of domestic natural resources, and, in the case of Japan and South Korea, the retirement or decommissioning of baseload nuclear power plants. These long-term trends lead to relative price stability of LNG in these markets. By contrast, newer LNG import markets such as India, the Middle East, Europe and South America, generally have various energy sources available, resulting in greater LNG price sensitivity.[26]

The LNG market has demonstrated two notable developments in recent years. First, as a result of the recent divergence of oil and natural gas prices, LNG prices (which are typically contractually linked to the price of oil) have become decoupled from the price of natural gas (as illustrated below). Second, in recent years, the duration of LNG contracts has shifted from longer term to shorter term. The traditional long-term (e.g., 20- to 30-year) contract model has two components: a sales contract and a transportation contract. The prices are indexed to an agreed measure (e.g., a hub), while volume is agreed upon on a take-or-pay basis—i.e., the seller agrees to a minimum delivery and the buyer pays a penalty in the event that it does not take the agreed-upon volume.[27] In recent years, a rise in LNG contracts with destination flexibility, a surge in regasification capacity, price differentials across regions and growth in the LNG shipping fleet have strengthened the short-term LNG market.[28] In 2013, the short-term market (i.e., contracts of 5 years or fewer) comprised 33% of global LNG trade,[29] up from 20% five years prior and 8% ten years prior.[30]

INDEXED PRICE—GAS AND OIL



25 IGU World LNG Report.
26 BCG Report.
27 BCG Report.
28 BCG Report.
29 IGU World LNG Report.
30 "Prospects for Development of an Asian LNG Trading Hub," King & Spalding, February 2014.
31 Henry Hub is a natural gas distribution hub in Louisiana. Henry Hub's prices are generally viewed as an indicator for the prices in the broader North American natural gas market.
32 West Texas Intermediate ("WTI") is a grade of crude oil; its prices are used as a benchmark for oil prices.
33 Japan LNG Import refers to the average price of LNG imports to Japan.
34 U.K. Gas Import refers to the average price paid for natural gas imports to the U.K.

2. Overview of Global Market Participants

The global LNG market involves an ecosystem of participants whose constructive involvement is necessary to any export development project. The table below describes many of these participants.

GLOBAL LNG MARKET PARTICIPANTS

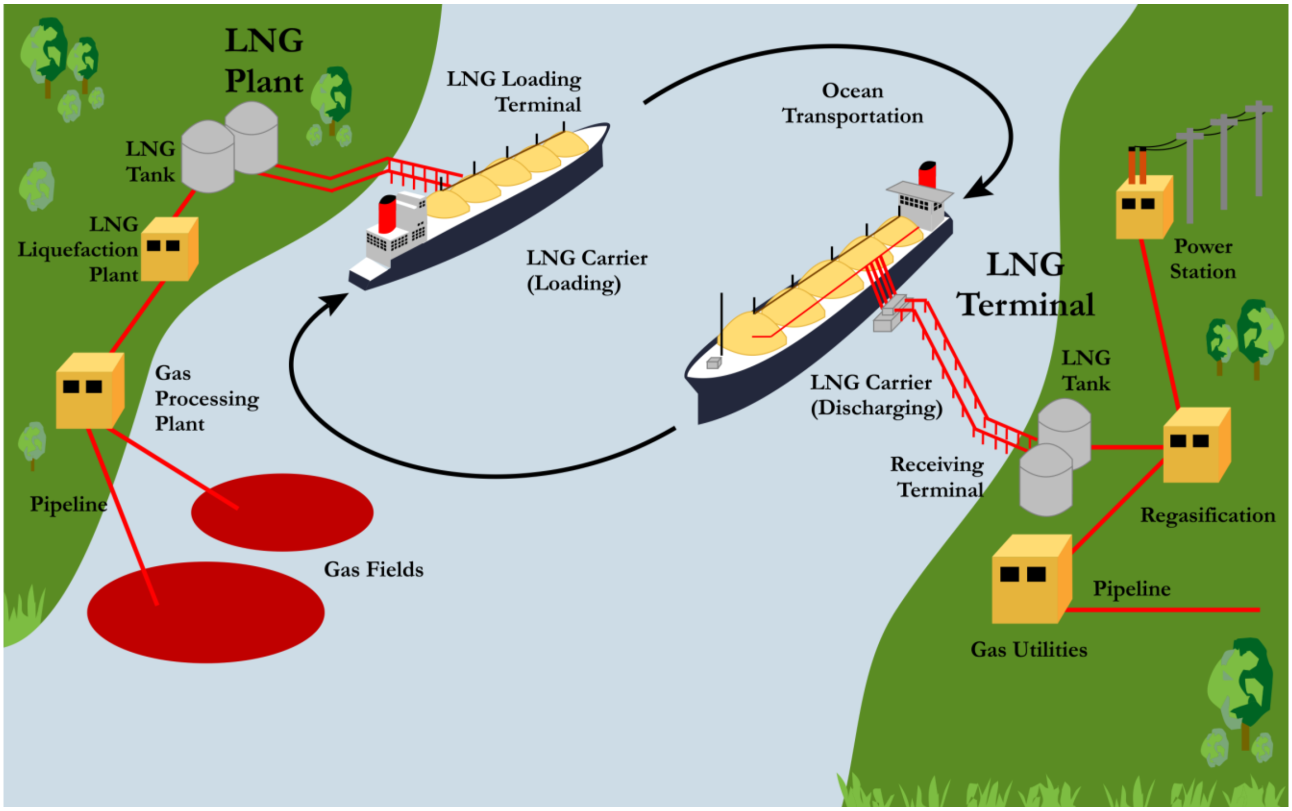
SOVEREIGN GOVERNMENTS	■ Control exploration and production rights on their land; a principal player in the LNG value chain; their approval and support can be necessary in any development project ■ LNG export market is highly concentrated in a small number of nations: □ Qatar (33%), Malaysia (10%) and Australia (9%)[35] ■ World's largest reserves of natural gas are found in: □ Russia (1,688 Tcf) and Iran (1,187 Tcf)[36]
PRODUCERS	■ Obtain land rights from governments, and explore and extract energy assets ■ Natural gas producer market is relatively concentrated; large players can be broadly categorized into: □ State-owned entities such as Gazprom (1,241 Tcf of gas reserves)[37] or Saudi Aramco (288 Tcf)[38] □ Multinational entities such as Exxon (26 Tcf), BP (10 Tcf) and Conoco (10 Tcf)[39]
ENGINEERING AND CONSTRUCTION COMPANIES	■ Develop the infrastructure necessary for gas treatment (prior to pipeline transportation), LNG liquefaction and, at a later stage, regasification (i.e., transformation of LNG into gas) ■ LNG engineering and construction market is very concentrated, given that there are few companies with the expertise and scale necessary to develop these large-scale projects; major players include: □ Bechtel (private; 2013 revenue of ~$39 billion) □ Fluor (~$9 billion market capitalization) □ Chicago Bridge & Iron (~$5 billion market capitalization) □ KBR (~$2 billion market capitalization)
PIPELINE OPERATORS	■ Transport gas through pipelines to LNG processing and export facilities ■ Natural gas pipeline industry is heavily concentrated; major North American players include: □ Enbridge (~$44 billion market capitalization) □ TransCanada (~$35 billion market capitalization) □ Spectra (~$25 billion market capitalization) □ Kinder Morgan (~$44 billion market capitalization) □ Energy Transfer Partners (~$23 billion market capitalization)
SHIPPING/ TRANSPORTATION	■ Transport LNG over water to end markets ■ Players include both LNG producers and independent shipping companies;[40] top three companies (Nakilat, MISC and Bonny Gas) tied to specific projects (in Qatar, Malaysia and Nigeria, respectively) ■ There are currently 357 LNG vessels worldwide[41] □ In contrast to the concentrated export market, the three largest companies comprise only about 18% of the worldwide fleet, by number of vessels
UTILITIES (E.G., POWER PRODUCERS, GAS DISTRIBUTION COMPANIES)	■ Power producers generate electricity using regasified LNG ■ Gas distribution companies deliver regasified LNG as natural gas to customers ■ Countries with the largest regasification capacity include: □ Japan (184 MTPA), U.S. (132 MTPA), Korea (92 MTPA) and Spain (42 MTPA) ■ Utility industry is relatively fragmented globally, but concentrated on a local basis as incumbent players provide the bulk of services for a particular region □ These companies include the state-owned utility Korea Gas Corporation ("KOGAS"), the largest single LNG importer in the world (41 MTPA);[42] the Japanese utilities Tokyo Electric Power and Chubu Electric Power, which now purchase LNG together and are one of the largest importing entities in the world (40+ MTPA);[43] and the state-owned Taiwanese utility CPC Corporation (13 MTPA)[44]

Source: FactSet.
Note: Pricing data as of January 2, 2015.

35 IGU World LNG Report.
36 IGU World LNG Report.
37 "Gas and oil reserves," Gazprom.
38 "Facts & Figures 2013," Saudi Aramco.
39 EY Oil and Gas Study.
40 "Liquefied Natural Gas: Understanding the Basic Facts," DOE, 2005.
41 IGU World LNG Report.
42 "South Korean KOGAS Looks to O10-17 LNG Cargoes in Oct-Nov: Sources," Platts, August 28, 2014.
43 "Tepco, Chubu Electric Form World's Largest LNG Buyer," Wall Street Journal, October 7, 2014.
44 "Taiwan Keen to Import US LNG from Shale Gas-fed Projects: Report," Platts, June 6, 2013.

The illustration below demonstrates the relationships among many of these players in the global LNG value chain.

GLOBAL LNG VALUE CHAIN



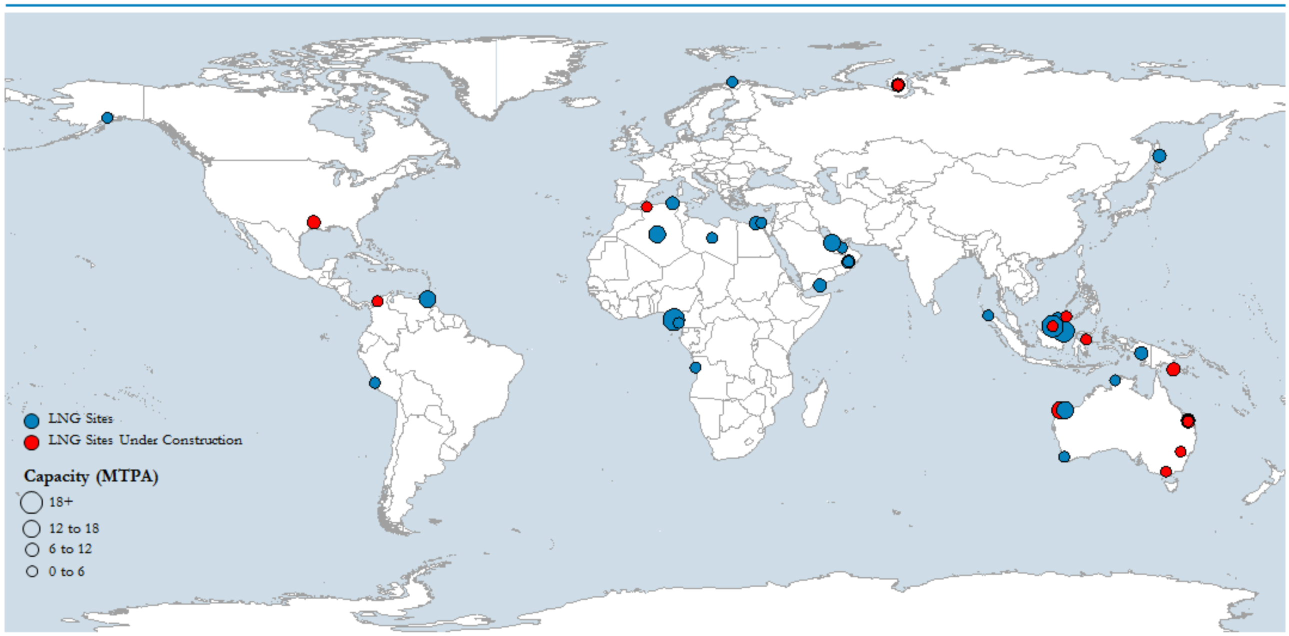
Source: PTTLNG, modified.

3. Overview of Global LNG Projects

The maps below show LNG projects worldwide that are either complete or under construction. As of 2014, there are 31 existing LNG sites, with an additional 22 sites under construction. The existing sites have a capacity of 294 MTPA, for an average of 9.5 MTPA per site. The vast majority of facilities that are under construction will likely come online in the next three years, with 73% of new liquefaction capacity expected to be completed by 2017 and 90% by 2018.[45]

Existing global LNG sites are generally dispersed geographically. However, new supply, evidenced by sites under construction, is centered in Australia and Indonesia and, to a lesser extent, the Americas. This demonstrates Europe's perceived decreasing share of future demand and the increasing demand of northern Pacific Rim countries, such as Japan. Despite the concentration of new LNG site construction, the number of countries exporting LNG is still expected to grow only slightly, as new projects come online in Colombia and Russia.[46]

GLOBAL LNG SITES



Source: IGU World LNG Report.
Note: Single dots may represent multiple LNG plants at a single site.

GLOBAL LNG SITES

	Number	Capacity (MTPA)
Existing	31	294
Under Construction	22	117
Total	**53**	**411**

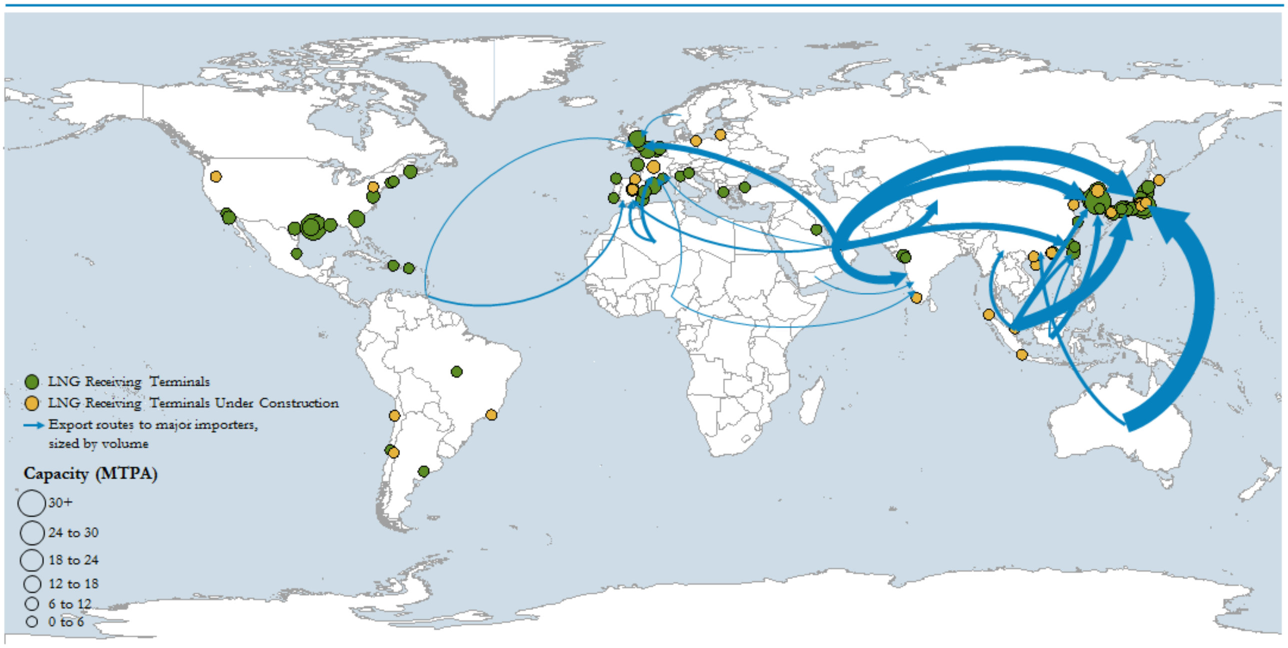
Source: IGU World LNG Report.

45 IGU World LNG Report.
46 IGU World LNG Report.

Worldwide, there are 74 existing LNG receiving terminals, with an additional 26 under construction. The receiving terminals have an average capacity of 8.5 MTPA. The prevalence of existing receiving terminals in Western European countries reflects these countries' historical position as major importers of LNG. The numerous existing receiving terminals in the U.S. reflect the country's push for fuel alternatives prior to the discovery of substantial amounts of domestic shale gas and cost-effective extraction technologies that have led to vast amounts of domestic gas in the Lower 48.[47]

The number of countries importing LNG, which has exceeded the number of exporting countries since 2002, is expected to continue to grow. In the coming years, Asian nations, in particular China, Japan and Indonesia, will likely be constructing major LNG receiving terminals. The relatively smaller capacity of LNG terminals in South American nations reflects the use of LNG as a cost-effective near-term energy solution.[48]

GLOBAL LNG RECEIVING TERMINALS



Source: IGU World LNG Report.
Note: Single dots may represent multiple LNG receiving terminals at a single site.

GLOBAL LNG RECEIVING TERMINALS

	Number	Capacity (MTPA)
Existing	74	628
Under Construction	26	74
Total	**100**	**701**

Source: IGU World LNG Report.

47 IGU World LNG Report.
48 IGU World LNG Report.

B. Overview of Natural Resources in Alaska

The Alaska State Constitution provides that "it is the policy of the State to encourage the settlement of its land and the development of its resources by making them available for maximum use consistent with the public interest."[49] Largely driven by this policy, oil extraction has been an integrated component of Alaska's economy over the past 50 years, and revenues from oil production have constituted the vast majority of the State's revenue. During this same period, the production of natural gas has been limited. Current forecasts of oil production, however, suggest that State revenues from this activity are likely to decrease significantly in the coming years. This trend (together with many other factors including increased global demand for LNG) has galvanized support for a large-scale natural gas project in Alaska.

1. Overview of Oil in Alaska

a. Resource Description

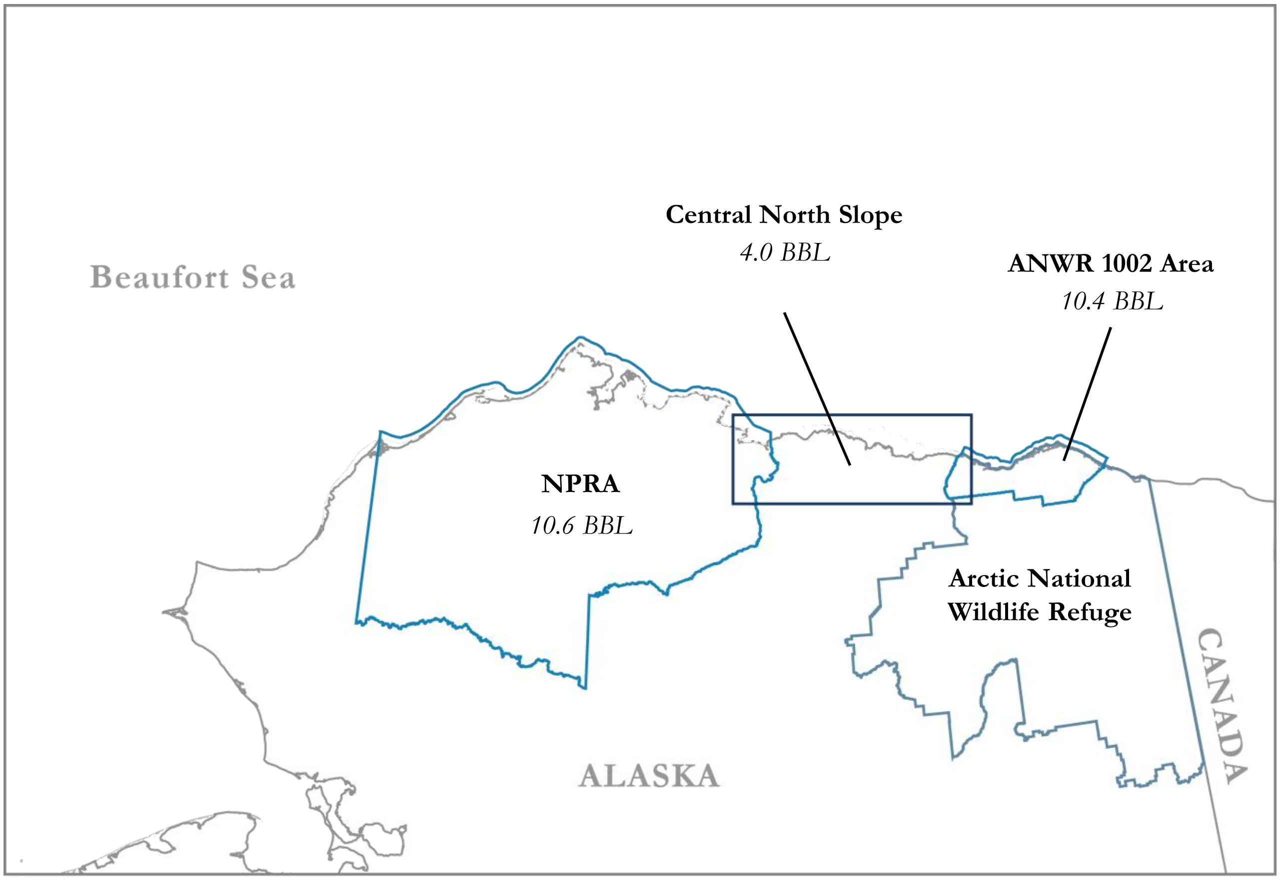
Oil production is critical to Alaska's fiscal position and financial stability. According to the Fall 2014 Revenue Sources Book,[50] proceeds from oil contributed 88% of total deposits to Alaska's General Fund for fiscal year ("FY") 2014 (this includes production taxes, royalties, property taxes and corporate income taxes associated with oil production). Consequently, variations in the price or the production volume of oil can have a material effect on Alaska's annual budget.

According to the U.S. Geological Survey ("USGS"), there are an estimated 24.9 billion barrels ("BBL") of undiscovered, technically recoverable petroleum in the Arctic Alaska Petroleum Province ("AAPP"), which encompasses all land north of the Brooks Range and Herald Thrusts and, to date, accounts for the vast majority of oil reserves in Alaska. These oil reserves are spread across the North Slope of Alaska in three designated areas: the National Petroleum Reserve-Alaska ("NPRA"), Central North Slope and the Arctic National Wildlife Refuge ("ANWR 1002 Area"). NPRA has ~10.6 BBL of undiscovered oil, Central North Slope has ~4.0 BBL of undiscovered oil and ANWR 1002 Area has ~10.4 BBL of undiscovered oil. These reserves and their locations are illustrated on the following map.

49 Alaska Constitution Article VIII, Section 1.

50 "Fall 2014 Revenue Sources Book," The State of Alaska, 2014 ("Fall 2014 Revenue Sources Book").

AAPP REGIONS AND UNDISCOVERED OIL

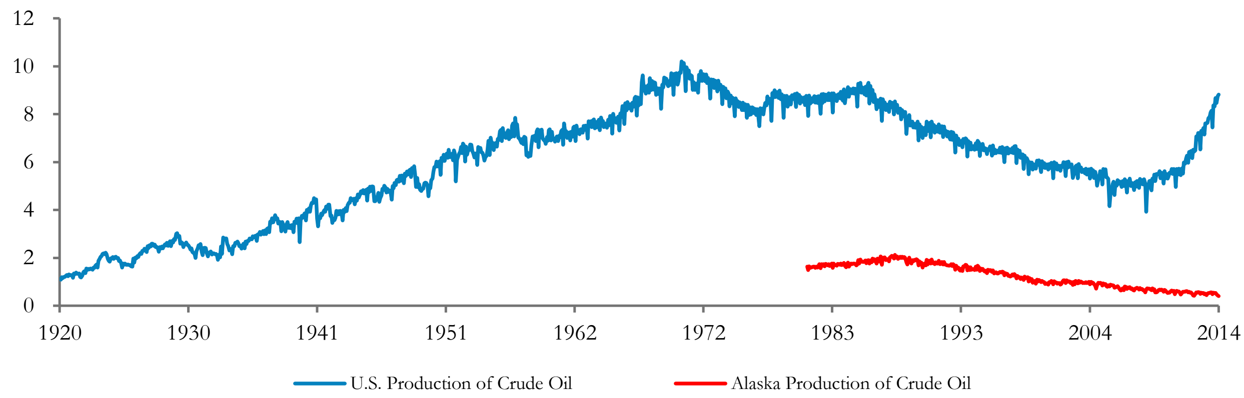


Source: U.S. Geological Survey Paper 1732-A.

b. Summary of Historical and Forecasted Oil Production and Operations

Alaska oil constitutes a significant, but decreasing, proportion of total U.S. production. U.S. and Alaska oil production peaked in 1970 and 1988, respectively. Since 1988, U.S. oil production has decreased consistently, and fell to 5.0 million barrels per day ("MMBD") by 2008. However, since 2008, higher oil prices and new drilling technologies have stimulated industry activity in North Dakota, Texas and the Gulf of Mexico. Concurrently, Alaska production has continued to decrease, as illustrated in the following chart.

CRUDE OIL PRODUCTION (MMBD)



Source: EIA.

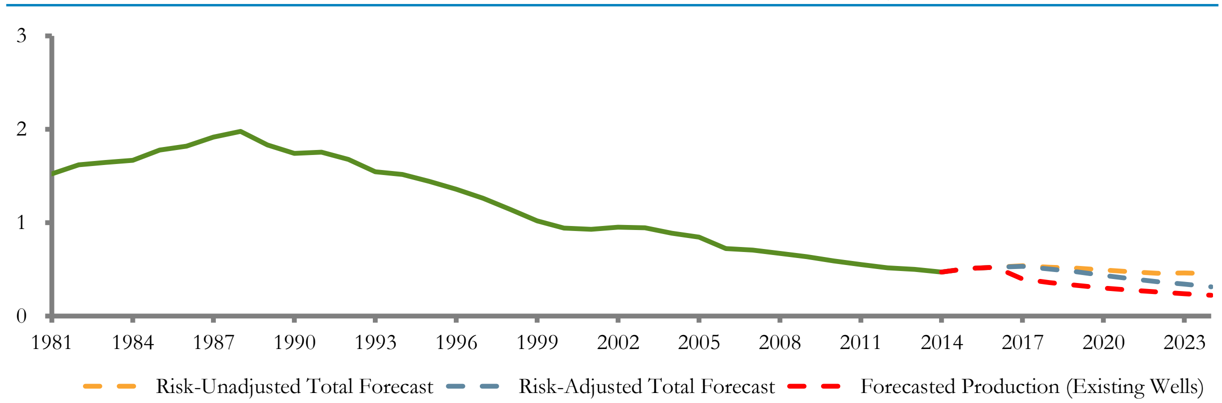
Following slight forecasted increases in production in 2015 and 2016, production from Alaska's currently-producing oil reserves is expected to decline each year over 2017 – 2024, yielding annual production from existing wells by 2024 that is approximately 44% of expected output in 2015. Even after taking into account forecasted new oil production, Alaska's overall production is expected to decrease to approximately 62% of expected 2015 output by 2024. These forecasts are summarized in the table and chart below.

ALASKA NORTH SLOPE OIL PRODUCTION FORECAST (MMBD)

	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E
Forecasted Production (Existing Wells)	0.510	0.524	0.397	0.359	0.329	0.302	0.278	0.258	0.239	0.222
Growth/(Decline) Rate	*4%*	*3%*	*(24%)*	*(9%)*	*(8%)*	*(8%)*	*(8%)*	*(7%)*	*(7%)*	*(7%)*
Risk-Adjusted New Oil	0.000	0.000	0.137	0.144	0.145	0.134	0.122	0.111	0.104	0.092
Memo: New Oil Share of Risk-Adjusted Total Forecast	*0%*	*0%*	*26%*	*29%*	*31%*	*31%*	*30%*	*30%*	*30%*	*29%*
Risk-Adjusted Total Forecast	0.510	0.524	0.534	0.503	0.473	0.436	0.400	0.369	0.343	0.315
Year-Over-Year Forecasted Growth/(Decline) Rate	*0%*	*3%*	*2%*	*(6%)*	*(6%)*	*(8%)*	*(8%)*	*(8%)*	*(7%)*	*(8%)*
Memo: Risk-Unadjusted Total Forecast[(a)]	*0.510*	*0.524*	*0.539*	*0.523*	*0.514*	*0.494*	*0.474*	*0.459*	*0.462*	*0.455*

Source: Fall 2014 Revenue Sources Book.
Note: Risk-adjusted amounts calculated by the State. Amounts represent the expected value of future production based on the size of the project and its likelihood of success.
(a) Reflects "high" case.

ALASKA NORTH SLOPE CRUDE OIL PRODUCTION (MMBD)



Sources: EIA and Fall 2014 Revenue Sources Book.

2. Overview of Natural Gas in Alaska

a. Resource Description

According to a report prepared by DeGolyer and MacNaughton[51] (referenced in the Project's U.S. Department of Energy ("DOE") export application), there is an estimated supply of approximately 63.5 Tcf of natural gas in Alaska. This supply is spread between the North Slope, Cook Inlet and offshore Continental Shelf (in depths of less than 200 meters); a summary of the resource is presented below.

OVERVIEW OF ALASKA NATURAL GAS RESOURCE

		RESOURCES MOST LIKELY		TOTAL RESERVES + RESOURCES (Tcf)
ALASKA REGION AND ASSESSMENT SEGMENT	RESERVES (Tcf)	PROBABLE (Tcf)	POSSIBLE (Tcf)	
Alaska Onshore				
North Slope	0	30.2	15.0	45.2
Cook Inlet	1.1	0.7	1.4	3.2
Alaska Offshore (0 – 200 Meters)				
Beaufort Shelf	0	2.0	12.0	14.0
Cook Inlet Basin	0	0.4	0.7	1.1
Grand Total – Expected Supply Scenario	**1.1**	**33.3**	**29.1**	**63.5**

Source: DeGolyer and MacNaughton Report.

b. Existing Alaska Natural Gas Operations

Alaska's natural gas production comes primarily from two regions: the Cook Inlet and the North Slope. Although natural gas production in the State is several orders of magnitude smaller than that of oil, natural gas has nonetheless played a significant role in Alaska's economy, both as a primary fuel source for generating electricity and heating Alaska's cities, and as an export product in its LNG form.

i. Prudhoe Bay

The Prudhoe Bay oil discovery in 1968 in the North Slope of Alaska that led to the construction of the Trans-Alaska Pipeline System ("TAPS") also included natural gas estimated at the time to be 26 Tcf (and since revised upward as outlined above). Since 1968, various plans have proposed to move North Slope gas to market. To date, Alaska does not export North Slope gas, although the gas is used for electricity generation in the North Slope and for enhancing oil recovery in Prudhoe Bay

[51] "Report on a Study of Alaska Gas Reserves and Resources for Certain Gas Supply Scenarios as of December 31, 2012," DeGolyer and MacNaughton, Prepared for Locke Lord LLP, April 2014 ("DeGolyer and MacNaughton Report").

by reducing oil surface tension and aiding mobility. The remaining extracted gas is re-injected into the Prudhoe Bay reservoir to maintain pressure and help increase oil production.[52]

ii. Cook Inlet

For over half a century, Cook Inlet natural gas exports have served as an engine for Alaska economic growth. In 1959, the year that Alaska became a state, Cook Inlet became the site of the State's first major commercial gas discovery. Since then, Cook Inlet has produced more than 7.8 Tcf of gas for in-State use and export.[53]

Tidewater natural gas from Cook Inlet is used predominantly as a fuel for heating Alaska's largest city, Anchorage, and the "railbelt" area connected to the electrical grid. Additionally, approximately one-third of the natural gas produced at Cook Inlet had historically been cooled into LNG and exported to Japan. The LNG plant at Cook Inlet, located on the Kenai Peninsula in Nikiski, Alaska, operated between 1969 and 2011. This plant, the world's second-ever intercontinental LNG project, both monetized natural gas resources in Alaska and spurred the initial destination infrastructure that has allowed Japan to become the world's leading LNG importer.[54]

In the early 2000s, local demand for natural gas began to expand in Alaska. In 2011, the EIA estimated that Alaska consumers used 85 billion cubic feet ("Bcf") of natural gas, which accounted for 63% of power generation in the State and 53% of heating fuel. Over the same time period, gas production in Cook Inlet declined, primarily because additional reserves were not developed. As a result of these changing dynamics, the LNG plant at Cook Inlet ceased operations in 2011.[55]

However, by Fall 2013, new drilling had produced a surplus of gas supply and the State requested that Conoco renew its DOE export permit to provide Cook Inlet producers with access to LNG end markets. In May 2014, the Cook Inlet LNG plant resumed shipments with a renewed permit. The approved permit allowed for the export of LNG to non-free trade countries, most notably Japan.[56]

52 Fall 2013 Revenue Sources Book.
53 Fall 2013 Revenue Sources Book.
54 Fall 2013 Revenue Sources Book.
55 Fall 2013 Revenue Sources Book.
56 "ConocoPhillips to reopen LNG plant, resume exports," Alaska Journal of Commerce, April 17, 2014.

C. Overview of Alaska Natural Gas Legislation

Since 1968, various plans have proposed to move North Slope natural gas from Prudhoe Bay to markets, including to the Pacific Rim and the Lower 48. Although no North Slope gas has been exported to date, both Federal and State efforts have brought projects to near realization. These efforts are highlighted in the timeline below.

TIMELINE OF ALASKA NATURAL GAS LEGISLATION

DATE	EVENT DESCRIPTION
1976	The U.S. Congress passes the Alaska Natural Gas Transportation Act ("ANGTA"), which provides for the expedited development of a pipeline to deliver natural gas from Alaska to the Lower 48
1977	The U.S. and Canadian governments approve the construction of the Alaska Highway Project, a pipeline along a route that follows the Alaska Highway through Canada to reach the Lower 48
1977	Federal Power Commission, now the Federal Energy Regulation Commission ("FERC"), recommends an overland pipeline route through Canada to move Alaska gas to the Lower 48
1978	Congress passes the Natural Gas Policy Act and the Powerplant and Industrial Fuel Use Act ("Fuel Use Act") in response to natural gas shortages that had been due to federally regulated price controls. The Fuel Use Act restricted construction of new power plants and boilers using natural gas and oil as primary fuels, encouraging instead the use of coal, nuclear energy and alternative fuels
1980s	U.S. Maritime Administration conducts study indicating that U.S. LNG sales to Pacific Rim nations had greater economic potential than those to West Coast U.S. markets, but market prices for LNG failed to support the commencement of such a project
1987	Congress lifts previous Fuel Use Act restrictions on new-build natural gas and oil power plants
1998	Alaska Legislature passes Alaska Stranded Gas Development Act ("Stranded Gas Act"), which allows the State to negotiate special fiscal, tax and royalty terms, and regulatory terms with North Slope oil producers for "stranded gas," which is defined as gas that "is not being marketed due to prevailing costs or price conditions as determined by an economic analysis by the Department of Revenue Commissioner for a particular project"
2001	National Energy Plan includes a recommendation to expedite construction of an Alaska natural gas pipeline to serve the Lower 48. Alaska natural gas interagency task force formed; includes the State Department, Department of Interior, Department of Transportation, DOE and FERC
2002	Alaska voters approve a ballot measure that creates the Alaska Natural Gas Development Authority ("ANGDA"), vested with the authority to act as a shipper and obtain financing for a project
2003	Alaska Legislature reauthorizes Stranded Gas Act
2004	Congress passes the Alaska Natural Gas Pipeline Act, which establishes a federal project coordinator, provides for loan guarantees, and offers tax and regulatory incentives for a pipeline project
2007	Alaska Legislature passes the Alaska Gasline Inducement Act ("AGIA"), which provides for 50% reimbursement for developers' expenses up to $500 million, in exchange for agreeing to terms, including following the State's timeline
2010	Alaska Legislature creates the AGDC as a subsidiary of the Alaska Housing Finance Corporation; tasks the AGDC with advancing the Alaska Stand Alone Pipeline ("ASAP")
2013	Alaska Legislature makes AGDC an independent corporation, folds together and consolidates operations with ANGDA
2014	SB 138 signed into law, facilitating Alaska participation in the Project

Sources: Fall 2013 Revenue Sources Book and "Searching for a Market: The 40-year Effort to Develop an Alaska Natural Gas Project," Office of the Federal Coordinator, July 2014 ("Office of the Federal Coordinator—'Searching for a Market'").

D. Overview of Previous and Current Alaska Natural Gas Projects

Efforts to monetize the large natural gas reserves in Prudhoe Bay began in the mid-1970s, shortly before the completion date of TAPS. Since then, every Alaska Governor has tried to spur construction of a natural gas pipeline. Those efforts have thus far been unsuccessful; however, in recent years, the importance of the construction of such a pipeline has increased as North Slope oil production has declined and the economics of LNG exports have become more attractive.[57]

In 1976, Congress passed ANGTA to expedite the development of a pipeline to deliver North Slope natural gas to the Lower 48. The following year, the U.S. and Canadian governments approved the construction and ownership of a pipeline along a route that followed the Alaska Highway through Canada to reach customers in the Lower 48 (the "Alaskan Northwest Project"). However, deregulation of the U.S. domestic natural gas industry, through legislation such as the 1978 Natural Gas Policy Act and Fuel Use Act, led to an increase in the supply of natural gas and a price reduction for the destination markets of the Alaskan Northwest Project. As a result, the pipeline project never materialized.[58]

Throughout this period, various other projects competed with the Alaskan Northwest Project for regulatory approval. The El Paso LNG project contemplated transporting North Slope natural gas to California by first tracing the route of TAPS from Prudhoe Bay to Valdez, and then linking up with LNG export facilities that would ship to California. There was also a proposal for an "over-the-top" offshore route, dubbed Arctic Gas, which would have crossed over the Arctic Ocean to Canada and ultimately connected with U.S. East Coast markets.[59] These projects were rejected under the same federal certification process that approved the Alaska Northwest Project. Interest in a gas pipeline did not pick up significantly again until the late 1990s when rising prices and demand in the Lower 48 galvanized both policymakers and the energy industry.[60]

The resurgence of U.S. demand for natural gas circa 2000 prompted reconsideration of constructing a natural gas pipeline. Policymakers in the Alaska Legislature as well as in Congress passed preliminary legislation for natural gas pipeline projects connecting Alaska with the Lower 48. These laws led to negotiations between the State administration and the producers that culminated in a contract in 2006 that was rejected by the Alaska State Legislature.[61]

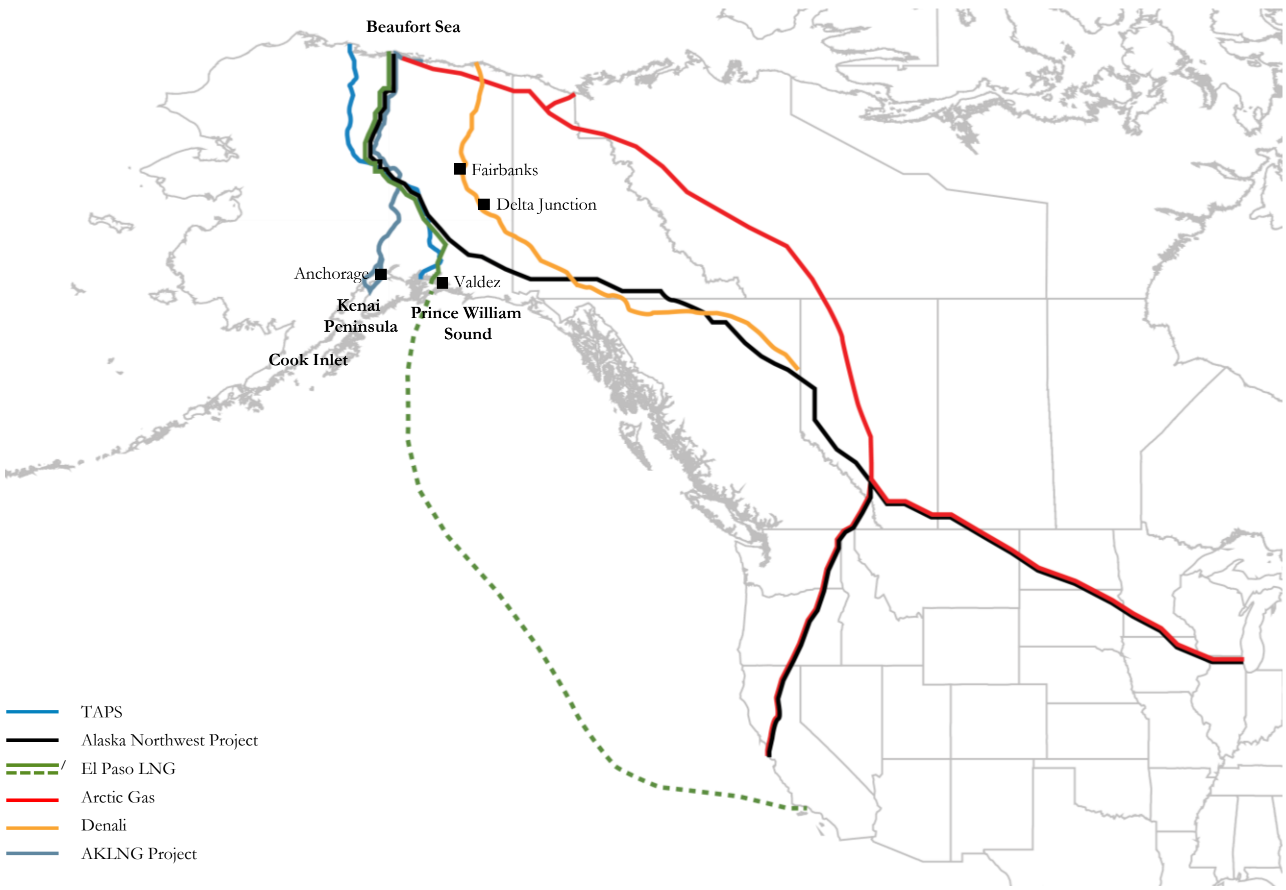
In 2007, the Alaska State Legislature passed the AGIA, which provided for 50% reimbursement for a developer's expenses (up to $500 million) in exchange for agreeing to terms, including following the State's timeline.[62] TransCanada, a Canadian pipeline company, was awarded the license, and Exxon later agreed to work with them on the project. In 2008, BP and Conoco launched a competing joint venture, Denali, which contemplated a pipeline that crossed Alaska, the Yukon and

57 Fall 2013 Revenue Sources Book.
58 Fall 2013 Revenue Sources Book.
59 Office of the Federal Coordinator—'Searching for a Market'.
60 Fall 2013 Revenue Sources Book.
61 Fall 2013 Revenue Sources Book.
62 Office of the Federal Coordinator—"Searching for a Market."

British Columbia to Alberta. These projects were ultimately abandoned after changed dynamics in the U.S. natural gas market made exports to the Lower 48 economically infeasible.[63]

In 2012, the chief executives of Exxon, Conoco and BP wrote to Alaska's Governor stating that they, together with TransCanada,[64] had begun studying a pipeline to a Southcentral Alaska LNG facility that would export gas to Asian markets, rather than the Lower 48—these efforts initiated the currently proposed AKLNG Project. The Project is estimated to have a total cost of \$45 – \$65 billion (in 2012 dollars), and would include a gas treatment plant, a 42-inch diameter pipeline and an LNG export facility in Nikiski on the Kenai Peninsula.[65]

PREVIOUS AND CURRENT ALASKA NATURAL GAS PROJECTS



Sources: Fall 2013 Revenue Sources Book and Office of the Federal Coordinator.

63 Fall 2013 Revenue Sources Book.
64 In October 2011, Alaska's Governor had requested that these parties work together to evaluate the economic feasibility of a project to address in-State gas needs and serve LNG export markets abroad.
65 Fall 2013 Revenue Sources Book.

E. Investment Thesis

The supply of natural gas in Alaska (and particularly in the North Slope) represents a valuable investment opportunity for the State and its residents. Given current downward trends in Alaska oil production and associated State revenue, in-State natural gas production could support Alaska's State budget well into the future. Political figures within the State have recognized the opportunity for natural gas production to stabilize Alaska's budget and, consequently, support for the Project has been growing. Other stakeholders, including North Slope producers and pipeline operators, see the potential development of Alaska's gas as a compelling investment decision. Most importantly, Alaska citizens stand to benefit from the development of the Project in many ways, including in-State job opportunities, lower-priced natural gas and Project revenues that flow to the State.

Alaska's supply of natural gas is abundant by many measures. For example, the export of 20 MTPA (i.e., the level proposed in the Project's DOE export license application) would rank Alaska as the fourth-highest exporter of LNG in the world, following Qatar (81 MTPA), Malaysia (25 MTPA) and Australia (23 MTPA).[66] Below is a table that demonstrates how an illustrative 20 MTPA export from Alaska would compare with exports from the top 10 LNG exporting countries over the past several years.

COMPARISON OF ALASKA'S POTENTIAL EXPORTS WITH THAT OF OTHER EXPORTERS (MTPA)

2009		2010		2011		2012		2013		2014E	
Qatar	38.2	Qatar	58.7	Qatar	58.7	Qatar	79.5	Qatar	77.2	Qatar	79.8
Malaysia	22.8	Indonesia	23.9	Malaysia	23.2	Malaysia	23.4	Malaysia	24.7	Malaysia	24.8
Alaska	**20.0**	Malaysia	23.2	Indonesia	23.9	Australia	21.2	Australia	22.2	Australia	23.7
Indonesia	19.4	**Alaska**	**20.0**	**Alaska**	**20.0**	Nigeria	20.6	**Alaska**	**20.0**	**Alaska**	**20.0**
Australia	18.7	Australia	19.5	Australia	19.5	**Alaska**	**20.0**	Indonesia	17.0	Nigeria	19.3
Trinidad	15.9	Nigeria	18.4	Nigeria	18.4	Indonesia	19.1	Nigeria	16.9	Indonesia	18.4
Algeria	15.9	Trinidad	15.4	Trinidad	15.4	Trinidad	14.7	Trinidad	14.6	Trinidad	14.7
Nigeria	12.1	Algeria	14.4	Algeria	14.4	Algeria	11.1	Algeria	10.9	Algeria	12.6
Egypt	10.0	Russia	10.5	Russia	10.5	Russia	11.0	Russia	10.8	Russia	10.3
Oman	8.4	Oman	8.9	Oman	8.1	Oman	8.3	Oman	8.6	Oman	8.4
Brunei	6.8	Egypt	7.3	Brunei	6.9	Brunei	6.9	Yemen	7.2	Brunei	7.2

Source: IGU World LNG Report.

The AKLNG Project holds a number of advantages over existing export operations in the rest of the world. These advantages include higher efficiency liquefaction and gas treatment, due to cold temperatures in Alaska. According to the Office of the Federal Coordinator, Alaska's efficiency

[66] Based on 2013A export volumes.

advantage over the Middle East could range from 12% – 14% due to average temperatures that are 44°F cooler (Alaska's 36°F average vs. the Middle East's 80°F). Since a key part of the liquefaction process involves cooling the gas to -259°F, colder temperatures yield more energy-efficient, less expensive gas treatment and liquefaction processes, which in turn lower the cost of producing each unit of LNG. Furthermore, the higher efficiency processes require less powerful equipment, lowering upfront capital costs.[67]

Another advantage is that Alaska natural gas has a higher heat content than that of competitors, making it more valuable in Asian end markets. This feature renders North Slope gas "market-ready" for Japan, South Korea and Taiwan in a way that, for example, Lower 48 natural gas is not. Alaska "wet" gas typically has a heat content of ~1.1 million British thermal units ("MMBtu") per thousand cubic feet ("Mcf") whereas "dry" U.S. pipeline gas typically has a heat content of ~1.02 MMBtu/Mcf. Although Asian end markets can convert drier gas into wet gas—and, at scale, can do so economically—the conversion process involves infrastructure and resources which render the drier gas costlier.[68]

Geographically, Alaska is well positioned to access high-demand markets in the Pacific Rim. Nikiski is roughly 3,800 miles from the major Japanese port of Yokohama and several nearby LNG terminals. By contrast, the proposed Kitimat project in British Columbia is almost 4,500 miles from Yokohama, and Russia's Yamal project in the Arctic is 7,800 miles away (the route is also ice-blocked much of the year). Additionally, direct access to Pacific countries proves a significant advantage over, for example, Gulf projects that face chokepoints (e.g., Panama Canal) and therefore higher shipping costs in reaching Asian markets.[69]

The Project provides other significant advantages such as low resource risk, given the large proven resources in Prudhoe Bay. Additionally, use of the existing infrastructure in Prudhoe Bay as well as the TAPS route makes the AKLNG Project more economically feasible relative to competing opportunities and lessens the environmental impact of the Project's development. Furthermore, the State is a highly stable governmental entity as compared to countries that are the site of large-scale development projects (e.g., Nigeria, Russia, etc.). Lastly, gas extraction will likely improve production efficiency in adjacent oil fields by using Point Thomson gas to maintain pressure in Prudhoe Bay oil fields.

67 "Alaska's Frigid Climate Could Give State an Edge in LNG," Office of the Federal Coordinator, June 2014. The cold climate, however, is not altogether beneficial. These advantages are to some extent offset by the higher costs of development and maintenance in colder environments. For example, the remote Arctic location of Prudhoe Bay and Point Thomson creates logistical issues during the development stage. Massive gas treatment plant modules may be delivered only in the summer months due to Arctic ice blocking routes in the winter.

68 "Alaska LNG Could Have Right Heat Content for Asia Buyers," Office of the Federal Coordinator, August 2013.

69 "Early Planning, Design, Engineering Are Key to LNG Project Success," Office of the Federal Coordinator, February 2014.

IV AKLNG Project Overview

IV. AKLNG Project Overview

Currently in its Pre-FEED phase, the AKLNG Project involves a diverse set of stakeholders, including citizens of Alaska, communities and municipalities, State and Federal government agencies, large multinational companies, and many other individuals and entities. The Project will require a substantial investment in infrastructure, including the construction of gas treatment and storage facilities, an 800-mile pipeline and marine facilities for the trans-Pacific shipment of LNG. As currently contemplated, the Project will involve approximately 2 – 4 years of additional planning followed by an estimated 5 – 6 years of construction. When completed circa 2024, the AKLNG Project is expected to be the largest LNG project in the U.S. and is expected to deliver LNG to various markets in Asia.

A. History

The AKLNG Project started to take form in October 2011, when Alaska's Governor requested that Exxon, BP, Conoco and TransCanada work together to evaluate the economic feasibility of a project to address in-State gas needs and serve LNG export markets abroad. By 2012, these parties had begun to coordinate their efforts and contribute resources to explore the opportunity. The parties then negotiated a Heads of Agreement with the AGDC and the State of Alaska, and ultimately executed this agreement in January 2014. The Heads of Agreement establishes non-binding guiding principles and partner roles for the Project as well as important commercial and operating arrangements among each of the key Project parties. The State's decision to partner with these parties allows for, among other things, cost and risk sharing, alignment of interests among key Project stakeholders and State participation in key aspects of the Project decision-making process.[70] Following the execution of the Heads of Agreement, the Project entered the pre-FEED phase in mid-2014.

B. Description, Overview of Facilities and Map

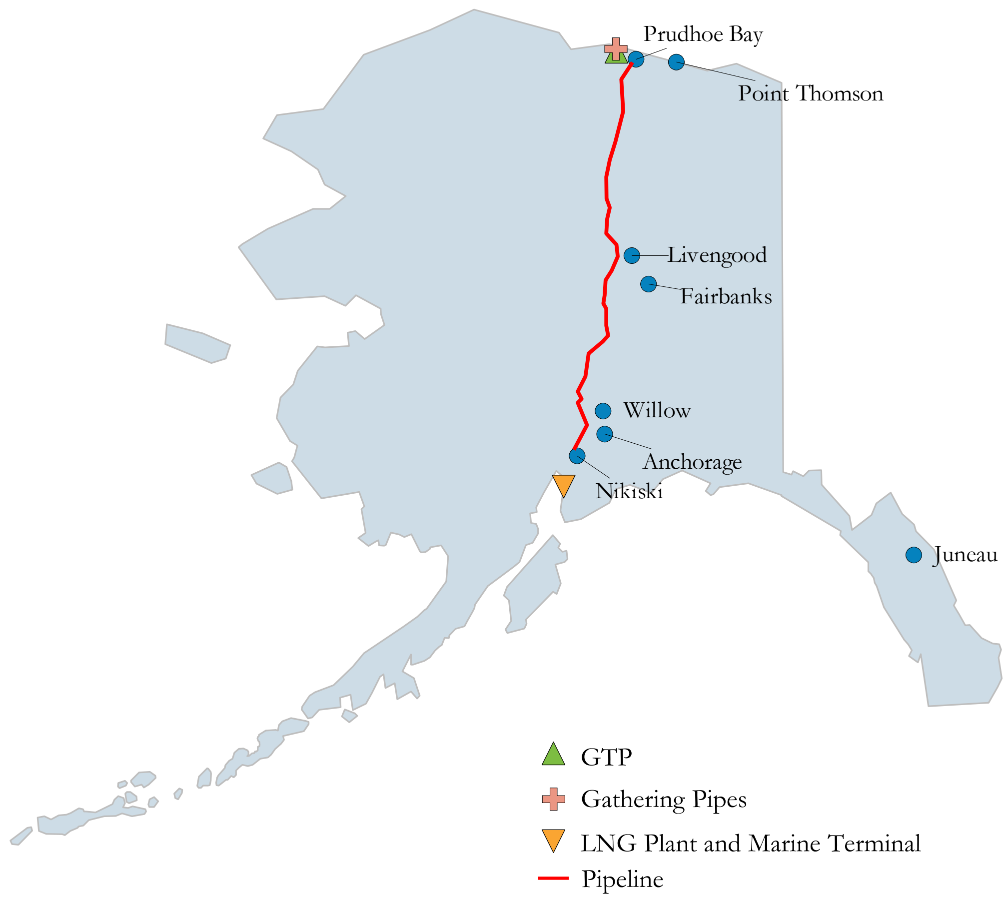
As currently contemplated, the Project primarily consists of the following three components: the GTP, the Pipeline and the LNG Plant. Natural gas produced at the Prudhoe Bay and Point Thomson fields in the North Slope will be transported via regional gathering pipes[71] to the GTP, where it will be treated to a level of quality (e.g., free of impurities, byproducts, water, etc.) sufficient to be transported through the Pipeline. The GTP is expected to be located adjacent to the existing Prudhoe Bay fields. The Pipeline will follow an 800-mile route from the GTP in Prudhoe Bay through Livengood in central Alaska and south to Cook Inlet. Multiple offtake points are planned along the route of the Pipeline to facilitate in-State gas distribution. After reaching Cook Inlet, the

70 "Heads of Agreement By and Among The Administration of the State of Alaska, AGDC, TransCanada Alaska Development Inc., ExxonMobil Alaska Production Inc., ConocoPhillips Alaska Inc. and BP Exploration (Alaska) Inc. for the Alaska LNG Project," January 2014 ("Heads of Agreement").

71 The gathering pipelines connecting the Prudhoe Bay/Point Thomson facilities with the GTP are also considered to be part of the Project.

gas will be processed at the LNG Plant, where it will be liquefied, stored at local storage facilities and shipped from a marine export terminal.

ALASKA LNG PROJECT MAP



Source: "Project Overview with AGDC," Alaska LNG Project Presentation, May 7, 2014 ("Project Overview with AGDC").

C. Key Stakeholders

The AKLNG Project involves a large number of stakeholders with various levels of participation, including the following parties:

		DESCRIPTION[72]
PROJECT SPONSORS	STATE OF ALASKA	■ Pursuant to SB 138, intends to become a part-owner of the AKLNG Project, with a currently contemplated economic interest of 25%
	EXXON	■ Multinational oil and gas company involved in upstream (exploration and production) and downstream (refining and distribution) energy markets, as well as chemicals manufacturing and the marketing of Exxon's various products ■ Market capitalization of ~$395 billion (largest publicly-traded oil and gas company in the world) ■ Among the producers involved in the development of North Slope natural gas (36% ownership of Prudhoe Bay,[73] 62% ownership of Point Thomson[74])
	BP	■ Multinational oil and gas company involved in upstream and downstream energy markets, as well as chemicals manufacturing and the marketing of BP's various products ■ Market capitalization of ~$115 billion ■ Among the producers involved in the development of North Slope natural gas (26% ownership of Prudhoe Bay,[73] 32% ownership of Point Thomson[74])
	CONOCO	■ Multinational oil and gas company involved exclusively in upstream energy markets ■ Market capitalization of ~$85 billion ■ Among the producers involved in the development of North Slope natural gas (36% ownership of Prudhoe Bay,[73] 5% ownership of Point Thomson[74])
	TRANSCANADA	■ North American energy company involved in the development and ownership of oil and gas pipelines, power generation and gas storage facilities ■ Market capitalization of ~$40 billion ■ Potential partner of the State for the GTP and Pipeline
	AGDC	■ An independent, public corporation of the State established to develop, finance and operate pipelines and other energy systems within the State, including the Project's LNG Plant
ALASKA ENTITIES	LEGISLATURE	■ Passed SB 138 in April 2014 ■ Must approve contracts between the State and other parties with a Project interest before these contracts are to become effective ▫ Contracts include the Heads of Agreement, as well as the Memorandum of Understanding ("MOU") and Firm Transportation Services Agreement ("FTSA") between the State and TransCanada
	MUNICIPALITIES/ COMMUNITIES[75]	■ Stand to benefit directly and indirectly from the development of the Project; SB 138 requires: ▫ Advisory planning group to advise on municipal involvement in the Project ▫ Department of Revenue to develop a plan and suggest legislation for municipalities, regional corporations and residents of the State to acquire ownership interests in the Project ▫ The establishment of the Alaska Affordable Energy Fund to develop infrastructure to deliver energy to areas of the State that are not expected to have access to the Pipeline[76]
	NATIVE CORPORATIONS	■ Stand to benefit directly from the development of the Alaska LNG Project; SB 138 requires the Department of Revenue to develop a plan and suggest legislation for these corporations to acquire ownership interests in the Project
	GOVERNMENT ENTITIES[77]	■ Consistent with the Alaska State Constitution's policy to encourage the maximum use and development of its resources consistent with the public interest, there are a number of Alaska government entities whose purpose is to manage and promote the development of its lands
FEDERAL ENTITIES[78]	OFFICE OF THE FEDERAL COORDINATOR	■ Established by Congress in 2004 to help expedite/coordinate federal permitting for construction of Alaska natural gas pipelines ■ Office coordinates with more than 20 federal agencies, the State of Alaska, tribal governments and other stakeholders, including the Project sponsors

Note: Pricing data as of January 2, 2015.

72 FactSet, Company and entity websites, SB 138.
73 "Prudhoe Bay Report 2013," BP.
74 "Point Thomson: Key gas field that's challenging to produce," Office of the Federal Coordinator, May 11, 2012.
75 Includes North Slope Borough, Denali Borough Assembly, Kenai Chamber of Commerce, Fairbanks North Star Borough, Cook Inlet Region Citizens Advisory Council, Mat-Su Borough, Nikiski Community Council, among others.
76 The amount to be deposited in the Fund is 20% of the revenue received from the State's royalty gas transported by the Alaska LNG Project, after payment of the constitutionally mandated 25% to the Alaska Permanent Fund.
77 Includes Alaska State Pipeline Coordinators Office, Alaska Department of Fish and Game, Alaska Department of Natural Resources, Alaska Departments of Geology and Geophysical Survey, Alaska Railroad Corporation, Alaska Department of Environmental Conservation, among others.
78 Also includes the Bureau of Land Management, DOE, Environmental Protection Agency, FERC, U.S. Army Corp of Engineers, U.S. Coast Guard, National Park Service, U.S. Fish and Wildlife Service, National Maritime Fisheries Service, among others.

D. Overview of Project Phases and Development Plan

The Project is currently in the Pre-FEED phase; the next key decision point (commencement of FEED) is planned for 2015/2016. The Project's phases are outlined in the table below.[79, 80]

	SELECTED ACTIVITIES	REQUIREMENTS TO PROCEED	SIZE

PRE-FEED (2014 – 2015)	■ Refine engineering and Project concept
	■ Evaluate preliminary business structure
	■ Form preliminary financing plan
	■ Perform environmental activities/technical data collection
	■ File DOE export license
	  ■ Completed July 21, 2014
	  ■ The Project requests an export of up to 20 MTPA of natural gas for 30 years
		■ Government support secured
		■ Viable technical option identified
		■ Permits/land use arrangements in process
		■ Potential for commercial viability assessed
			■ Expected cost: $400 million[81]
			■ Expected workforce: 400 – 500

FEED (2016 – 2018)	■ Complete major Project engineering and design work ■ Finalize major commercial and EPC contracts ■ Finalize business structure ■ Secure financing arrangements	■ Government support secured ■ Permits, land use arrangements and construction financing secured ■ Key commercial agreements (e.g., individual gas/LNG sales and shipping arrangements) executed ■ EPC contracts executed ■ Commercial viability confirmed ■ FID	■ Expected cost: $1.8 billion[81] ■ Expected workforce: 500 – 1,500
EPC (2019 – 2023)	■ Finalize engineering ■ Receive funds ■ Execute procurement plan ■ Complete construction ■ Prepare for operations	■ Construction of GTP, Pipeline and LNG Plant ■ Secure permanent financing ■ Secure operating permits	■ Expected cost: $52.8 billion[81] ■ Expected workforce: 9,000 – 15,000
OPERATIONS (2024+)	■ Project produces 15 – 18 MTPA[82] ■ Project revenues flow to owners based on Project ownership percentages		■ Expected permanent workforce: 1,000

79 The Concept Selection phase ended in 2012.
80 Project Overview with AGDC.
81 Based on total expected cost of $55 billion (midpoint of $45 – $65 billion, in 2012 dollars).
82 DOE export license requests 20 MTPA.

E. Overview of Current Situation

Sizable and growing Asian demand for LNG, together with the potential for Alaska production, support the State's decision to pursue the development of Alaska's natural gas reserves. While the AKLNG Project has developed strong momentum, received numerous regulatory approvals and garnered widespread support, as with any project of its size, a number of risks exist, and the success of the Project will require careful planning and risk mitigation by the Project sponsors.

1. Alaska Market

According to the Project's DOE export application, the expected supply of natural gas reserves in Prudhoe Bay is more than sufficient to satisfy both in-State demand and the Project requirements for a 30-year export term at 20 MTPA.[83] This conclusion is based on the findings of various studies, including a report prepared by NERA Economic Consulting, and the AKLNG Project-commissioned DeGolyer and MacNaughton Report. The NERA Report estimates that approximately 47.5 Tcf of natural gas supply is necessary to meet estimated upstream lease operations fuel, Alaska in-State natural gas demand and export demand.[84] The DeGolyer and MacNaughton Report estimates Alaska total gas supply of 63.5 Tcf.[85]

STATE OF ALASKA'S EXPECTED EXCESS GAS SUPPLY

CATEGORY	AMOUNT (Tcf)	
Total Estimated Reserves and Resources	63.5	
Upstream Lease Operations Fuel (2013 – 2052E)	(10.2)	
In-state Use (2013 – 2052E)	(5.4)	Total = 47.5 Tcf
LNG Export Demand (i.e., 20 MTPA over 30-year LNG Export Term)	(31.9)	
Excess Gas Supply	**16.0**	

Sources: DeGolyer and MacNaughton Report, NERA Report.

DEMAND FOR ALASKA NATURAL GAS—DETAIL (Tcf)

		2013	2018E	2023E	2028E	2033E	2038E	2043E	2048E	Cumulative Total
Alaska Demand	Upstream Lease Operations Fuel	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	10.2
	In-State Use	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	5.4
LNG Export Demand		-	-	0.9	1.1	1.1	1.1	1.1	1.1	31.9
Total Natural Gas Demand		0.4	0.4	1.2	1.5	1.5	1.5	1.5	1.5	47.5

Source: NERA Report.

83 AKLNG – U.S. DOE Export Application.
84 "Socio-Economic Impact Analysis of Alaska LNG Project," NERA Economic Consulting, Prepared for Locke Lord LLP, June 19, 2014 ("NERA Report").
85 DeGolyer and MacNaughton Report.

2. Import Markets

The AKLNG Project would likely export LNG to countries that are projected to have strong long-term demand for LNG, including Japan, South Korea, China and India. While these markets currently exhibit substantial LNG demand, several factors may limit the magnitude of this demand in the future, including import capacity limitations and development of domestic or regional energy resources.

a. Japan

Japan's limited domestic energy resources and position as a major player in international trade make the nation a prime market for LNG. Japan is the world's largest end market for LNG with 2013 imports of 88 MTPA (37% of global volume).[86] This particularly high level of demand, however, is a relatively new phenomenon, driven primarily by the country's shift in fuel mix after the meltdown of nuclear reactors at the Fukushima power plant and the subsequent shutdown of nearly all nuclear power plants in the country. Between 2010 and 2013, Japan's LNG imports increased 25% and, for the first eight months of 2014, the country imported 11.9 Bcf/d of LNG to fuel its power plants.[87]

Japan's high LNG demand has driven an increase in the average cost of imports, from $9/MMBtu before the Fukushima incident to a high of over $18/MMBtu in 2012.[88] However, Japan's largest importers have started to negotiate contracts jointly and to use the country's status as a large importer of LNG to negotiate better pricing and mitigate future price increases.[89]

Certain risks exist to Japan's future LNG demand, including a resumption of nuclear energy generation, import capacity limitations and other factors. In September 2014, Japan's Nuclear Regulation Authority approved the use of approximately 1.8 gigawatts ("GW") of nuclear energy generation that was previously shut down.[90] Moreover, Japan currently operates 30 LNG terminals with a total capacity of 185 MTPA, which exceeds current levels of demand. Finally, Japan's low electricity demand growth and increased penetration of solar energy may also limit future LNG demand growth.[91]

b. South Korea

South Korea is the second-largest LNG importer in the world with imports of 41 MTPA (17% of global volume) in 2013. The country has no international oil or natural gas pipelines and, as a result, imports 97% of its fuel by tanker shipments of oil and LNG. Although the country has 203 Bcf of

86 IGU World LNG Report.
87 "Japan," EIA, July 31, 2014.
88 EIA.
89 EIA.
90 "Japan Nuclear Restart Weakens Oil and LNG Demand Incrementally," Energy Security Analysis, September 16, 2014.
91 "The Asian Quest for LNG in a Globalising Market," International Energy Agency, November 2014.

proven natural gas reserves, domestic gas production contributes less than 2% to its domestic energy consumption.[92]

Certain risks could dampen South Korean LNG demand growth. KOGAS, the single-largest LNG buyer in the world, has a monopoly on domestic natural gas sales and deferred a number of LNG deliveries in November 2014 due to excess inventories of gas.[93] Moreover, KOGAS recently announced plans to sell down its equity stake in LNG Canada, a 12 MTPA LNG project, as it expects to purchase less natural gas than previously estimated.

c. China

China is the third-largest LNG importer in the world, with imports of 19 MTPA (8% of global volume) in 2013. Buoyed by growing LNG capacity (32 MTPA in 2013 vs. 6 MTPA in 2008) and economic growth, Chinese LNG demand is expected to grow significantly over the next decade.[94] Chinese natural gas usage is estimated to account for over 10% (approximately 60 MTPA) of the country's energy mix by 2020, compared to only 4% in 2010. Since China's coal market alone is currently seven times larger than the world LNG market, increased penetration of LNG in China could be a significant source of growth for exporters.[95]

Certain risks could make Chinese LNG demand forecasts highly variable. China has begun to develop its own shale gas resources and is expected to boost domestic production by 65% to 6.8 Tcf/year in 2019 from its current level of 4.1 Tcf/year.[96] As a result, over half of incremental gas demand for the country could be met by domestic resources. Moreover, China imports gas from Central Asia and Myanmar, and has strengthened ties with Russian gas exporters after signing a $400 billion gas supply agreement in May 2014. If these ties continue to strengthen, China could have access to a large source of pipeline-delivered natural gas, which would likely be more cost-effective than imported LNG. Given these factors, and despite growth in overall Chinese LNG demand, China's proportion of LNG as a percentage of its total energy supply is expected to decrease by 2025.[97]

d. India

India is the fourth-largest LNG importer in the world, with imports of 13 MTPA (5% of global volume) in 2013. Due to limited infrastructure and low production of domestic natural gas, India increasingly depends on LNG to meet growing electricity demand. While natural gas contributes only 12% of the country's energy mix (compared to the world average of 23%), estimates suggest

92 "South Korea," EIA, April 1, 2014.
93 "South Korea's Kogas to cut LNG imports in response to weaker local demand," Platts, November 20, 2014.
94 "China," EIA, February 4, 2014.
95 "Global LNG: Will New Demand and New Supply Mean New Pricing?" EY, March 19, 2013.
96 "Medium-Term Gas Market Report," International Energy Agency, June 10, 2014.
97 "The Asian Quest for LNG in a Globalising Market," International Energy Agency, November 2014.

that increased domestic gas-fired power generation and natural gas infrastructure could push Indian LNG demand to 27 MTPA by 2020.[98]

Several factors could limit the growth of India's LNG demand. The country has access to abundant coal reserves, which may serve as an inexpensive substitute for baseload power generation. Preferential allocation of domestic gas resources could limit the market potential for LNG going forward. In addition, the level of LNG imports depends heavily on the expansion of current regasification capabilities, as India's current regasification capacity is limited to 21 MTPA.[99]

3. Partner Roles and Commitments

The State is partnering with a number of energy companies in the development of the Project. The table below summarizes the roles of each partner as well as their stake in the Project.[100]

	ILLUSTRATIVE PROJECT OWNERSHIP (%)	ROLE
STATE OF ALASKA	■ 25%[101]	■ Constructive facilitation of the Project[102]
EXXON	■ 25%[101] ■ Represents 3% of current Exxon enterprise value[103]	■ Concept and integration team leader ■ Management committee member
BP	■ 25%[101] ■ Represents 9% of current BP enterprise value[103]	■ Commercial and producing fields team leader ■ Management committee member
CONOCO	■ 25%[101] ■ Represents 13% of current Conoco enterprise value[103]	■ LNG Plant team leader ■ Management committee member
TRANSCANADA	■ 0%[101]	■ Significant resource commitment ■ Management committee member

Source: Heads of Agreement.

98 BCG Report.

99 BCG Report.

100 TransCanada agreed to be responsible for 60% – 100% of the State's upfront capital costs related to construction of the GTP and Pipeline in exchange for the State's agreement to pay a tariff on each unit of natural gas moved by the Pipeline. The contracted arrangement between TransCanada and the State is further described below in Section IV.F.

101 25% ownership figure is illustrative. Ultimate Project ownership percentage will depend, for example, on each entity's share of Project gas, among other factors, and may vary from this amount.

102 May include, for example, use of eminent domain rights, approving funding, supporting federal export applications, permitting, appropriations for in-state infrastructure necessary for the Project as well as drafting, introducing and supporting necessary legislation, etc.

103 Based on 25% of expected Project ownership costs of $13.7 billion (midpoint).

4. Key Project Milestones Achieved to Date

Since the Project started to take its current form in Fall 2011, a number of milestones have been achieved that have allowed for further advancement. Key milestones to date are presented below.

PROJECT MILESTONES

DATE	EVENT DESCRIPTION
October 2011	■ Alaska's Governor requests that Exxon, BP, Conoco and TransCanada work together to evaluate the economic feasibility of a project to address in-State gas needs and serve LNG export markets abroad
March 30, 2012	■ Chief Executives of Exxon, Conoco and BP write to former Governor Parnell regarding their initial work with TransCanada to assess the viability of an Alaska LNG Project
October 1, 2012	■ Exxon, Conoco, BP and TransCanada outline the key aspects of the AKLNG Project, including expected costs and a development timeline
October 7, 2013	■ Exxon, Conoco, BP and TransCanada identify Nikiski as the site for the proposed liquefaction port and export terminal
January 14, 2014	■ The State, Exxon, Conoco, BP and TransCanada execute a Heads of Agreement and an MOU outlining terms for participation in the AKLNG Project, including the State's equity stake in the Project
July 2, 2014	■ The State, Exxon, Conoco, BP and TransCanada sign a formal commercial agreement for the Project, beginning the Pre-FEED phase
July 18, 2014	■ AKLNG Project applies for authorization from the DOE to ship LNG to countries that do and do not currently have free trade agreements with the U.S.
September 5, 2014	■ AKLNG Project submits request to FERC to begin pre-filing process
October 1, 2014	■ AKLNG Project files two reports with FERC that are required to initiate the environmental impact review
November 21, 2014	■ DOE authorizes LNG exports from the Project to countries that currently have free trade agreements with the U.S.

Sources: "Alaska North Slope Natural Gas Line Project History," Office of the Federal Coordinator, March 4, 2014 and Office of the Federal Coordinator and Press Releases.

5. Risks

The AKLNG Project presents a number of risks, including potential for cost overruns during construction and commodity price risk. The table below describes various identified risks and potential mitigants that are typical of large-scale LNG projects.

	DESCRIPTION OF RISK	POTENTIAL MITIGANTS
DEVELOPMENT	■ Project is abandoned following development stage (and associated expenditures) ■ Investment required is too large/concentrated (e.g., represents ~3%, 9% and 13% of Exxon, BP and Conoco's enterprise value, respectively)	■ Ongoing/iterative assessment of Project feasibility, including size of ownership interests
COST OVERRUNS	■ Project encounters cost overruns during construction of GTP, Pipeline and/or LNG Plant	■ EPC contracts with appropriate risk transfer provisions ■ Third-party contracts with partners (e.g., TransCanada) that are positioned/able to share risk ■ Ongoing/iterative assessment of Project feasibility prior to construction
COMMERCIAL	■ Project is unable to achieve favorable commercial terms (or terms required to make the Project viable)	■ In-depth market analysis ■ State participation in Project ■ Partner/sponsor marketing strategy ■ Ongoing/iterative assessment of Project feasibility
REGULATORY	■ Project fails to receive required regulatory approvals (e.g., FERC) ■ Project fails to receive DOE export license ■ Project is delayed as a result of litigation	■ Early stakeholder outreach and communications strategy ■ Regulatory concessions and iteration of Project plan ■ Political support and strategy
COMMODITY PRICE	■ Expected LNG prices too low to support Project economics ■ Realized LNG prices much lower than budgeted levels	■ Fixed- or partially fixed-price long-term contracts prior to construction ■ Decoupling of price from traditional indices ■ Hedging strategy ■ State participation in Project ■ Take-or-pay contracts ■ Ongoing/iterative assessment of Project feasibility, including with respect to commodity price scenarios
OVER-SUPPLY/ COMPETING PROJECTS	■ Market saturation is reached in global LNG market ■ Competing projects (e.g., those in the Lower 48, Canada, Latin America, Australia, etc.) possess more favorable characteristics than Alaska LNG Project	■ In-depth market analysis ■ Take-or-pay contracts ■ Ongoing/iterative assessment of Project feasibility, including with respect to commodity price scenarios
DEMAND	■ Demand for LNG decreases as a result of a variety of factors (e.g., revival of nuclear power industry in Japan, fuel switching in other markets)	■ In-depth market analysis ■ Take-or-pay contracts ■ Flexibility in delivery of LNG

F. Analysis of Alaska's MOU with TransCanada

The State has entered into an agreement with TransCanada (the MOU) that outlines the parties' relationship with respect to the development and management of the GTP and Pipeline. The MOU transfers financing responsibilities for and control of the State's equity share in the GTP and Pipeline to TransCanada. Further, the MOU details TransCanada's terms of service for transporting Alaska's gas share via the GTP and Pipeline. Selected facts and observations regarding the MOU are summarized in the table below.

ANALYSIS OF TRANSCANADA MOU

FACTS

1. The State transfers financing responsibilities for and control of the State's equity share in the GTP and Pipeline to TransCanada
   - AGDC has the option to purchase up to a 40% interest in the partnership distributions associated with the GTP and Pipeline prior to the FEED phase of the Project (circa December 31, 2015)
     - Partnership distributions would be subject to TransCanada control on budgetary factors (e.g., timing)
   - TransCanada is responsible for between 60% and 100% (depending on exercise of the option) of the State's upfront capital costs related to GTP and Pipeline construction
2. The State commits to 25-year FTSA with TransCanada
   - The State pays TransCanada a tariff for each unit of natural gas moved by the GTP and Pipeline, based on capital structure and return criteria:
     - 75/25 debt-to-equity ratio for rate purposes[104]
     - Fixed TransCanada ROE of ~12% and cost of debt of ~5%[105]
3. If either the State or TransCanada terminates the agreement at any point before FID, the State is responsible for reimbursing TransCanada's planning and development costs (including internal development costs[106]) and interest; however, the State would maintain the option to proceed with the Project on its own[107]
   - TransCanada may terminate the contract if it does not secure debt financing on terms it finds satisfactory within three months from FID

OBSERVATIONS

1. The State is responsible for funding an estimated $13.7 billion without TransCanada participation vs. $7.0 billion with TransCanada
   - The State reduces its capital requirements throughout Project planning, design and development
     - Exposes the State to 13% – 18% of the total projected upfront Project costs; allows the State to retain 25% of the gas share in the operational Project
     - The State would still be responsible for repaying TransCanada's upfront investment via the return of capital mechanism established in the tariff
   - Shifts Project management responsibilities to TransCanada, but reduces the State's operational control
   - Potential complexities associated with TransCanada involvement in other projects
2. Reduces the State's share of revenues by $200 – $360 million per year (depending on exercise of the option)
   - 75/25 debt-to-equity ratio for rate-making purposes reduces the State's tariff, seemingly favorable debt-to-equity ratio for the State, relative to that of similar regulated ratebase arrangements
3. The State retains virtually all Project risk under the MOU
   - Contract termination by either party results in the State reimbursement of TransCanada's planning and development costs
   - While the State is temporarily shielded from cost overruns during planning and development, the State ultimately bears these costs via the tariff, which provides a 100% return of capital (as well as a return on capital) to TransCanada

Source: Alaska MOU with TransCanada and Black & Veatch Model, dated February 2014.

104 This capital structure commences on the second anniversary of the in-service date, and continues through the term of the FTSA. During development/construction and expansions/maintenance, Project capital structure is 70% debt and 30% equity.

105 The agreed-upon ROE and cost of debt are each subject to a "Rate Tracker Differential", amounting to the increase or decrease in the 30-year U.S. Treasuries yield at FID relative to such yield at the effective date of the MOU.

106 Includes ~$70 million incurred on the Alaska portion of the AGIA project.

107 Should either the State or TransCanada terminate the MOU before FID, the State is responsible for reimbursing TransCanada's development costs. In the case where the State terminates or where the Alaska State Legislature does not ratify either the MOU or the FTSA, then the State must reimburse TransCanada development costs plus interest of 7.1% (i.e., the Allowance for Funds Used During Construction ("AFUDC") amount).

G. Overview of Total Project and Alaska-Specific Economics[108]

The AKLNG Project has an expected overall cost of $45 – $65 billion (midpoint estimate of $55 billion), while the State's portion (assuming 25% participation) is expected to cost $11.3 – $16.3 billion (midpoint estimate of $13.7 billion[109]). The participation of the State and the producers is premised upon achieving an adequate return on this upfront investment through Project revenues during operations.[110]

1. Project Investment Timeline

As described earlier, the Pre-FEED phase of the Project is expected to cost ~$0.4 billion, the FEED phase of the Project is expected to cost ~$1.8 billion and the EPC phase of the Project is expected to cost ~$52.8 billion.[111] The table below sets forth the expected annual investment for the various facilities of the Project during each phase.

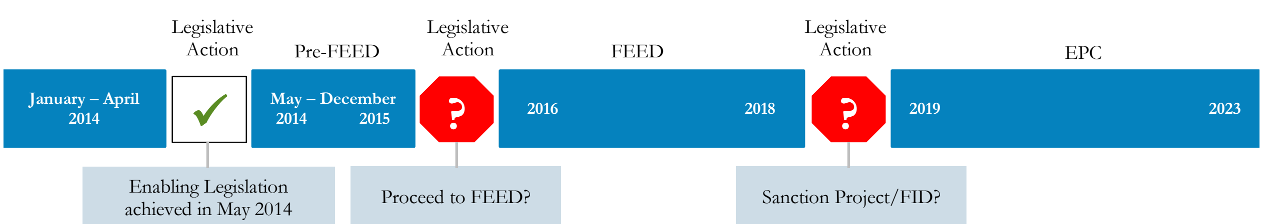
TOTAL PROJECT INVESTMENT ($ IN MILLIONS)

	PRE-FEED		FEED			EPC				
	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E
GTP	$43	$88	$184	$216	$139	$1,659	$2,847	$2,933	$2,417	$1,867
Pipeline	43	88	184	216	139	1,990	3,417	3,519	2,900	2,240
LNG Plant	57	117	245	288	186	3,815	6,549	6,746	5,558	4,294
Total	**$142**	**$292**	**$613**	**$721**	**$464**	**$7,464**	**$12,814**	**$13,198**	**$10,875**	**$8,401**
Phase Total	**$434**		**$1,798**			**$52,752**				

Source: Black & Veatch Model, dated February 2014.
Note: Figures are presented in nominal dollars.

The Project is currently in the Pre-FEED phase, which is expected to last through 2015/2016. At that point, the State can decide to exit the Project, or to move into the FEED phase. The FEED phase is expected to last until 2018, at which point the State can decide to exit the Project. After FID, the Project advances into the EPC phase.[112] The figure below illustrates the State's decision points at various phases throughout the Project timeline.

ILLUSTRATIVE PROJECT MILESTONES AND DECISION POINTS[113]



108 Project Overview with AGDC. Project costs in this section are shown in 2012 dollars, unless otherwise noted.
109 Midpoint estimate of $7.0 billion if TransCanada MOU remains in effect. Further detail regarding the State's financing need is presented in Section VI.A.
110 Net of any operating costs, including tariffs.
111 Based on Project cost midpoint of $55 billion.
112 Should either the State or TransCanada terminate the MOU before FID, the State is responsible for reimbursing TransCanada's development costs. In the case where the State terminates or where the Alaska State Legislature does not ratify either the MOU or the FTSA, then the State must reimburse TransCanada development costs plus interest of 7.1% (i.e., the AFUDC amount).
113 "Alaska LNG Project cash flow chart," Black & Veatch, March 2014.

2. Project Revenues

The primary components of Project revenue for the State would be as follows: [114]

Royalty

As an owner of the land on which the Project's natural gas is produced, the State is entitled to a royalty payment based on the total gas production of the Project. The State has the option to take its royalty payment in the form of cash or in kind (i.e., in units of natural gas).[115] As provided for by Alaska law and as set forth in the Heads of Agreement, the State has conditionally committed to taking its full royalty in kind (currently anticipated to be 12.5% of total gas production of the Project at the Prudhoe Bay facility[116]), depending on the satisfaction of key fiscal and contractual concerns.[117]

Production Tax

In addition to a royalty on production, the State is entitled to a tax on production. Gas that is produced within the State is subject to a tax as it leaves the ground. The tax does not apply to the royalty gas that is discussed above.[118] Similar to the royalty, the production tax may be delivered either in cash or in kind, and the State has given the option to each of the producers to elect which form of delivery will be used. If a producer exercises the option to pay in kind, the State would receive a fixed percentage of each producer's taxable gas from the Project (currently anticipated to be ~13%). Otherwise, the State will receive its production tax in cash.[115]

Property Tax

Additionally, the State receives revenues in the form of property taxes. Property tax is charged against any owners of property associated with the Project (e.g., land, Project facilities). In certain cases, local municipalities may also levy a property tax; however, such amount would be credited toward a property owner's State property tax obligation.[119]

State Corporate Income Tax

The final source of revenue for the State is corporate income tax, which would be levied on the taxable income of the various corporations associated with the Project.

114 The State, via AGDC, could also potentially be entitled to tariffs in the event that AGDC sells capacity on Project equipment to third parties in the future.
115 Heads of Agreement.
116 Royalty percentage at Point Thomson facility varies with different leases.
117 "Observations on Heads of Agreement," Black & Veatch, March 25, 2014.
118 Fall 2013 Revenue Sources Book.
119 Fall 2013 Revenue Sources Book.

a. State Revenue Projections

The tables and charts below set forth the current projections for the Project's revenue sources and cash flows.[120, 121] These projections contemplate two scenarios: one in which the State continues in its partnership with TransCanada ("TransCanada Partnership Scenario") and one in which the State invests in the Project on its own ("State Go-it-Alone Scenario"). These scenarios were chosen as "bookends" for the analysis, given that in the State Go-it-Alone Scenario, the State is fully responsible for financing its 25% equity interest in the Project and, in the TransCanada Partnership Scenario, the State receives the largest TransCanada financial participation contemplated by the MOU (i.e., assumes that the Alaska 40% buyback option is not exercised).

STATE OF ALASKA CASH FLOWS—25% EQUITY IN PROJECT ($ IN MILLIONS)

TransCanada Partnership Scenario	2014E	2015E	2017E	2019E	2021E	2023E	2025E	2027E	2029E	2031E	2033E	2035E	2037E	2039E	2041E	2043E
Unrestricted Royalty in Kind*	$0	$0	$0	$0	$0	$0	$934	$941	$979	$1,017	$1,056	$1,098	$1,143	$1,193	$1,248	$1,813
Restricted Royalty in Kind**	0	0	0	0	0	0	320	322	335	348	362	376	391	408	427	621
Total Royalty in Kind	$0	$0	$0	$0	$0	$0	$1,253	$1,262	$1,314	$1,365	$1,418	$1,473	$1,534	$1,601	$1,675	$2,434
Production Tax (Tax in Kind)	(30)	(32)	(36)	(74)	(383)	(421)	875	1,080	1,039	981	1,005	1,157	1,113	514	986	993
Upstream Corporate Income Tax	1	1	1	2	12	11	166	170	194	209	220	245	254	275	292	379
Midstream Corporate Income Tax	0	0	0	0	0	0	0	0	0	0	0	0	0	454	530	627
Upstream Property Tax***	4	6	12	23	73	122	167	172	164	153	140	126	135	192	177	1,018
Midstream Property Tax***	0	0	0	0	0	84	75	66	58	49	40	31	22	13	4	0
Project Ownership (LNG Plant)	(4)	(9)	(22)	(286)	(506)	(322)	451	437	422	407	390	372	353	333	311	287
Total	**($29)**	**($34)**	**($45)**	**($335)**	**($805)**	**($525)**	**$2,986**	**$3,188**	**$3,190**	**$3,162**	**$3,213**	**$3,405**	**$3,411**	**$3,381**	**$3,975**	**$5,737**

State Go-it-Alone Scenario	2014E	2015E	2017E	2019E	2021E	2023E	2025E	2027E	2029E	2031E	2033E	2035E	2037E	2039E	2041E	2043E
Unrestricted Royalty in Kind*	$0	$0	$0	$0	$0	$0	$983	$990	$1,028	$1,066	$1,105	$1,147	$1,192	$1,242	$1,298	$1,864
Restricted Royalty in Kind**	0	0	0	0	0	0	336	339	352	365	378	393	408	425	444	638
Total Royalty in Kind	$0	$0	$0	$0	$0	$0	$1,319	$1,329	$1,380	$1,431	$1,484	$1,540	$1,600	$1,668	$1,743	$2,502
Production Tax (Tax in Kind)	(30)	(32)	(36)	(74)	(383)	(421)	936	1,141	1,100	1,042	1,066	1,219	1,175	576	1,048	1,056
Upstream Corporate Income Tax	1	1	1	2	12	11	166	170	194	209	220	245	254	275	292	379
Midstream Corporate Income Tax	0	0	0	0	0	0	0	0	0	0	0	0	0	407	465	551
Upstream Property Tax***	4	6	12	23	73	122	167	172	164	153	140	126	135	192	177	1,018
Midstream Property Tax***	0	0	0	0	0	0	80	71	62	53	44	35	27	18	9	0
Project Ownership (GTP, Pipeline, LNG Plant)	(11)	(22)	(54)	(560)	(990)	(630)	874	851	826	800	772	745	717	688	659	634
Total	**($36)**	**($47)**	**($77)**	**($608)**	**($1,289)**	**($918)**	**$3,542**	**$3,734**	**$3,725**	**$3,687**	**$3,727**	**$3,910**	**$3,908**	**$3,823**	**$4,392**	**$6,139**

Source: Black & Veatch Model, dated February 2014, as adjusted by the State.
Note: Figures are presented in nominal dollars. State revenue sources and funds to be discussed in greater detail in Section V.A.
* Reflects funds available to the State as General Fund Unrestricted Revenue.
** Reflects 25.0% and 0.5% of Total Royalty in Kind allocated to the Permanent Fund and the School Fund, respectively.
*** Reflects estimated property tax cash flows to the State, net of payments to local municipalities.

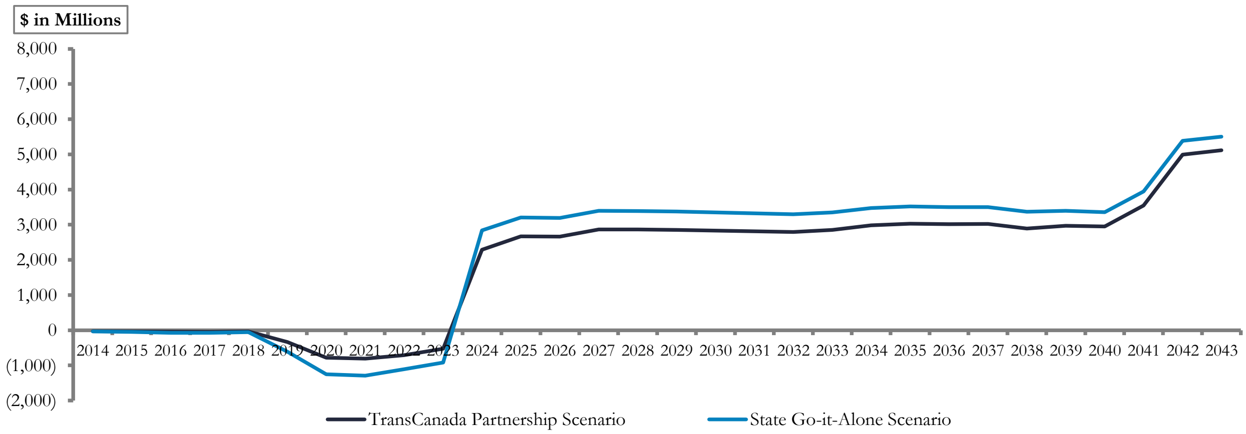
As can be seen above, in the TransCanada Partnership Scenario, the State makes a relatively lower upfront investment, but receives lower revenues during operations. In the State Go-it-Alone Scenario, the State must make a greater upfront investment, but is entitled to greater revenues during operations.

120 Cash flows are presented on a levered basis (i.e., cash flows to the State after projected debt service payments) assuming an illustrative 70% debt/30% equity Project capitalization and a 5% cost of debt.

121 Projections are based on Black & Veatch Model, dated February 2014, as adjusted by the State. Projections contemplate an LNG price of ~$16/MMBtu in nominal 2024 dollars; variations in the future price of LNG (e.g., as a result of declining oil prices, LNG oversupply, etc.) can have a significant impact on Project revenues, particularly the royalty and production tax in kind. Additionally, cash flows have been projected for 20 years; however, the Project could potentially remain in operation past this period, which could have the benefit of incremental cash flows to those shown.

Additionally, these cash flows have the benefit of being relatively stable during operation, with the added benefit of potential increases toward the latter stages of operation. These relationships are also illustrated in the following graph.

STATE OF ALASKA CASH FLOWS – 25% EQUITY IN PROJECT ($ IN MILLIONS)[122]



3. Project Operating Expenses

Included in the Project cash flows highlighted above are operating expenses, which are subtracted from revenues to determine the cash available for the State to provide a return on the debt and equity used to finance the upfront investment in the Project. These include tariffs, shipping costs and operations and maintenance ("O&M") expenses.

a. Tariffs

The sellers of the Project's LNG would be required to make tariff payments to the owners of the various facilities associated with bringing the LNG to market (i.e., the GTP, Pipeline and LNG Plant). The tariffs are structured such that (given expected Project volumes) the owner of the Project facilities would receive a predetermined rate of return on the initial investment.[123]

As was discussed in greater detail in Section IV.F, the State has agreed to pay a tariff to TransCanada in exchange for providing the financing for the State's 25% portion of the GTP and Pipeline.[123] The structure of the MOU allows for a 40% buy-back option, wherein AGDC would become a partner of TransCanada and thereby be entitled to a share of the proceeds from the State's tariff.[124]

If the State terminates its MOU with TransCanada and instead decides to fully finance its 25% portion of the GTP and Pipeline (in addition to its 25% portion of the LNG Plant), the State would be responsible for paying cost-based tariffs; however, the State would need to make the upfront investment required to construct the facilities.

122 Black & Veatch Model, dated February 2014, as adjusted by the State.

123 Actual tariffs are calculated based on a regulated ratebase formula, wherein debt and equity capitalization percentage and associated rates of return for each facility are agreed upon in advance. The levelized tariff is then calculated based on expected volumes, such that the agreed-upon rates of return are met.

124 Only pass-through costs (i.e., no return component).

b. Shipping Costs

The sellers of the Project's LNG may be responsible for paying the shipping costs associated with transporting natural gas from the marine terminal in Alaska to regasification terminals overseas.[125] Shipping costs are dependent on factors such as global shipping capacity and the price of fuel.

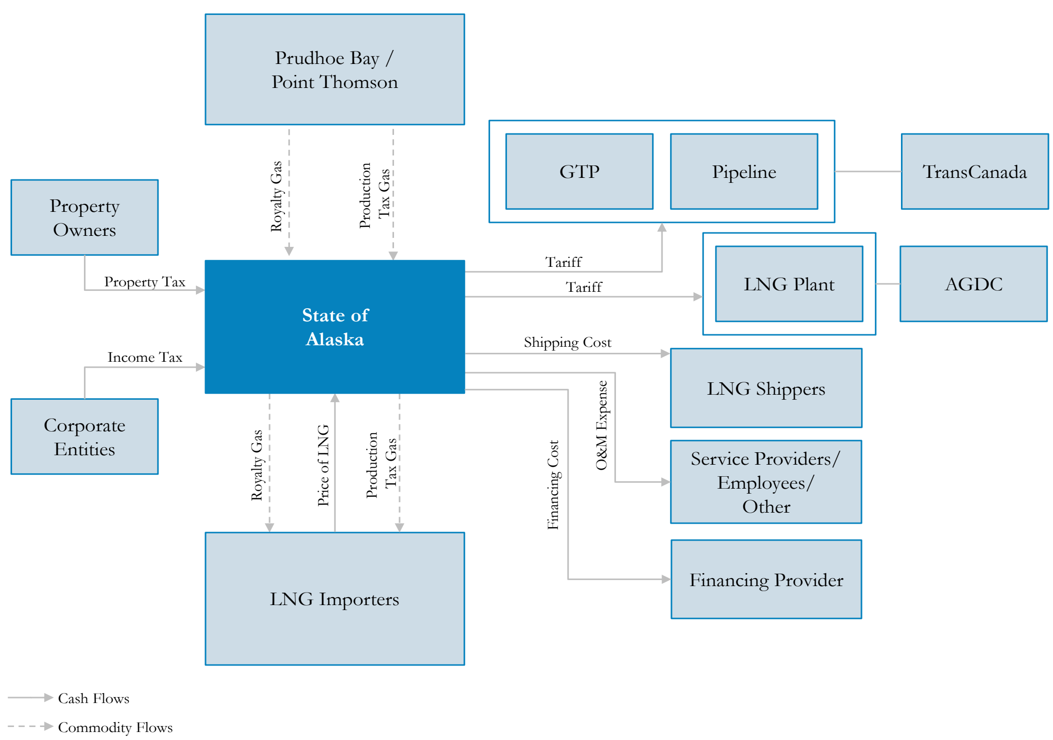
c. O&M Expenses

While the Project is in operation, various expenses would be incurred in order to, among other things, maintain equipment, pay employees and operate the Project's facilities. As an owner of the Project, the State would be required to pay its portion of these expenses.

4. Flow of Funds

The Project revenues and costs discussed involve a number of parties; the following chart illustrates the "flow of funds" between these parties.[126]

ILLUSTRATIVE FLOW OF FUNDS[127]



125 Under certain arrangements, the buyer of LNG could potentially be responsible for paying shipping costs.
126 Illustration assumes the State takes royalty and production tax in kind and pursues the TransCanada Partnership Scenario. Note that O&M expenses paid by the State would likely be facilitated via AGDC.
127 "State participation in AK LNG Project, Presentation to the House Finance Committee," Black & Veatch, April 2014, modified by Lazard.

5. Economic Analysis

The State expects to receive Project cash flows, as presented above in Section IV.G.2.a. An indicator of the Project's viability and overall economic benefit is its net present value ("NPV"), that is, the value of the Project's forecasted future cash flows discounted to today. Typically, if the NPV of a project is positive, it is considered economically viable, and vice versa. An unlevered discounted cash flow valuation analysis is a method of determining NPV that discounts unlevered free cash flows (i.e., cash flows that are available to all debt and equity investors) using a discount rate that reflects the overall risk associated with the projected cash flows. To arrive at unlevered free cash flows from the levered cash flows presented earlier, restricted revenues are excluded, and debt principal repayment and debt interest payments are added back.[128] The discount rate that is applied to these unlevered free cash flows is determined based on the perceived riskiness of the Project's cash flows; the analysis below assumes an 8% discount rate for illustrative purposes.

Additionally, analysis can be performed to determine the sensitivity of the Project's NPV to changing variables (e.g., the discount rate, Project revenues[129] and Project construction costs). This sensitivity analysis is presented below.

UNLEVERED DISCOUNTED CASH FLOW VALUATION ANALYSIS ($ IN MILLIONS)

NPV Sensitivity Analysis—TransCanada Partnership Scenario

DISCOUNT RATE	PROJECT REVENUE VARIATION				
	(10.0%)	(5.0%)	0.0%	5.0%	10.0%
6.0%	$15,380	$15,965	$16,550	$17,135	$17,720
7.0%	12,369	12,853	13,337	13,821	14,305
8.0%	9,947	10,349	10,751	11,154	11,556
9.0%	7,994	8,329	8,664	8,999	9,334
10.0%	6,413	6,693	6,973	7,253	7,532

DISCOUNT RATE	CONSTRUCTION COST VARIATION				
	10.0%	5.0%	0.0%	(5.0%)	(10.0%)
6.0%	$16,108	$16,329	$16,550	$16,771	$16,992
7.0%	12,926	13,131	13,337	13,543	13,749
8.0%	10,368	10,560	10,751	10,943	11,135
9.0%	8,307	8,485	8,664	8,842	9,021
10.0%	6,640	6,806	6,973	7,139	7,306

NPV Sensitivity Analysis—State Go-it-Alone Scenario

DISCOUNT RATE	PROJECT REVENUE VARIATION				
	(10.0%)	(5.0%)	0.0%	5.0%	10.0%
6.0%	$16,916	$17,537	$18,157	$18,778	$19,398
7.0%	13,279	13,793	14,307	14,821	15,335
8.0%	10,370	10,797	11,224	11,651	12,078
9.0%	8,038	8,394	8,751	9,107	9,463
10.0%	6,166	6,464	6,762	7,060	7,358

DISCOUNT RATE	CONSTRUCTION COST VARIATION				
	10.0%	5.0%	0.0%	(5.0%)	(10.0%)
6.0%	$17,282	$17,720	$18,157	$18,595	$19,033
7.0%	13,492	13,899	14,307	14,714	15,121
8.0%	10,465	10,845	11,224	11,603	11,983
9.0%	8,043	8,397	8,751	9,104	9,458
10.0%	6,102	6,432	6,762	7,092	7,422

Note: Analysis presented above is preliminary and illustrative in nature. Elements of the analysis, including the Project cash flows, discount rate, etc., will continue to evolve over time as a result of multiple factors (e.g., market treatment of similar LNG projects).

[128] Given that restricted revenues are required to flow to the Permanent Fund and the School Fund, they are not available to investors. Principal repayments and interest payments must be added back because these are payments that are specific to debt investors, whereas the unlevered free cash flow analysis is meant to examine cash flows available to any investor.

[129] Variations in Project revenues (royalty/production tax) are analyzed to illustrate the impact of variances in contracted gas prices from those forecasted to be received during Project operation (e.g., as a result of declining oil prices, LNG oversupply, etc.).

At an illustrative 8.0% discount rate and assuming no variations from currently forecasted revenues and construction costs, the expected NPV in the TransCanada Partnership Scenario would be ~$10.8 billion and the expected NPV in the State Go-it-Alone Scenario would be ~$11.2 billion. Given the State's higher exposure to construction risk and associated reliance on the Project's revenues in the State Go-it-Alone Scenario, changes in these variables have a greater impact on NPV.

V State of Alaska Financial Overview

V. State of Alaska Financial Overview

Alaska's present day reliance on oil revenues, combined with declining oil production forecasts, suggest that a new revenue source would help Alaska maintain its strong fiscal position. According to State projections, Alaska oil output is expected to decrease materially over the next ten years. Additionally, historically-low oil prices are placing further pressure on the State's budget. Absent other changes in the State's revenue sources, these trends may potentially have a negative impact on Alaska's balance sheet, credit rating and bonding capacity.

A. Budget

1. Projections

Alaska's finances are highly dependent on oil revenue. In FY 2014, oil revenues accounted for 88% of the State's unrestricted revenue (i.e., revenue used to fund the State's general expenses).[130] Accordingly, the State's financial projections are heavily dependent on oil production and price assumptions over the forecast period. The State's current projections reflect its goal of diversifying its revenue base away from oil to include revenue from natural gas (including increased production in Cook Inlet). Currently, the State projects that it can fund its budget without incremental natural gas revenue until 2023,[131] approximately when the Project would be expected to come online.[132]

The State's Office of Management and Budget ("OMB") addresses this issue in its 10-Year Plan, which has the stated objectives to: (1) balance the State budget between sources and uses of funds, (2) provide for essential State services and (3) protect Alaska's economic stability. To mitigate exposure to resource fluctuations, OMB proposes careful management of its primary reserve accounts, the Constitutional Budget Reserve Fund ("CBRF") and Statutory Budget Reserve Fund ("SBRF"). Accordingly, the CBRF and SBRF are drawn on to balance the budget in the event of revenue shortfalls and are replenished in the event of revenue surpluses.

Given current forecasts, the State projects that it will run a deficit over the next 10 years (i.e., it will draw on the SBRF and/or the CBRF in each of those years). The combined current value of the CBRF and SBRF[133] of ~$15.8 billion is projected to drop to ~($1.7) billion by 2024, fully depleting the SBRF and CBRF and creating a fund deficit; however, a new revenue source such as natural gas could allow the State to replenish its reserve funds while preparing it for future resource fluctuations.

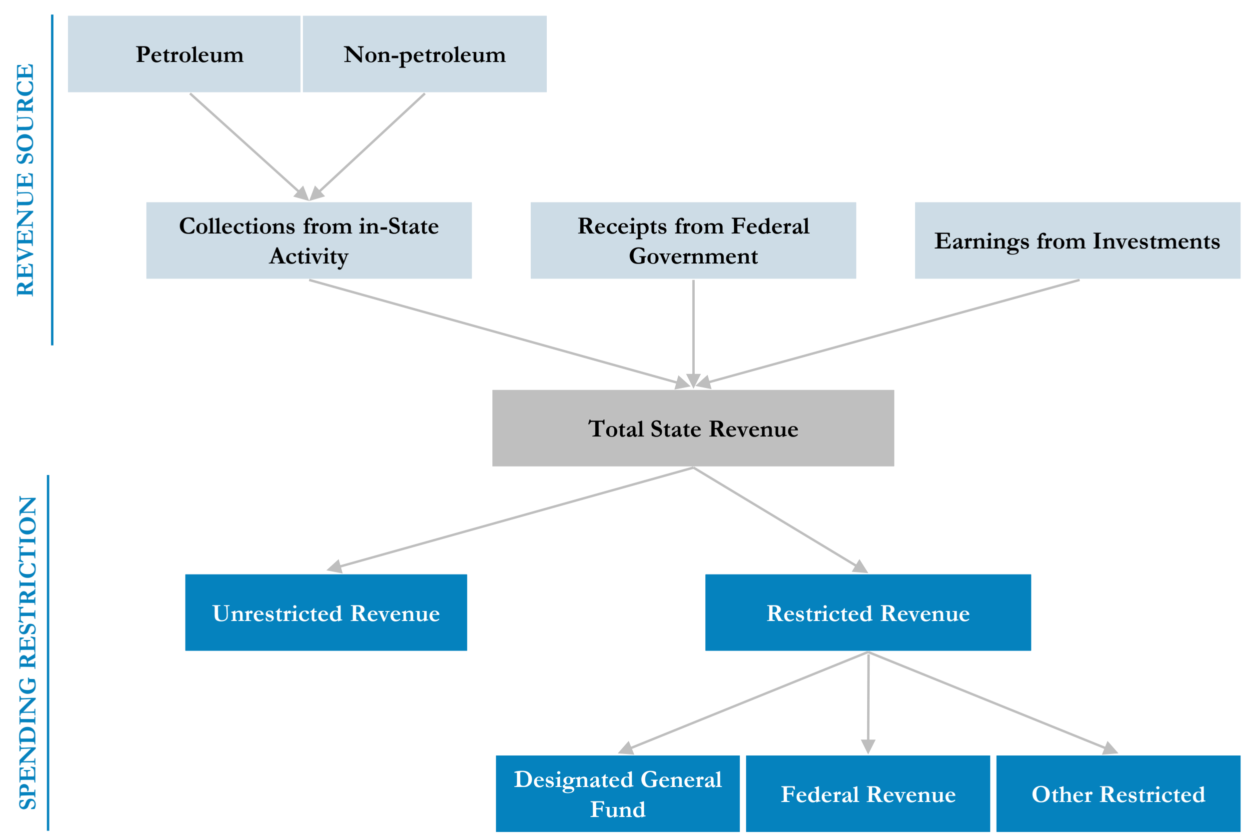
The State also uses a variety of mechanisms intended to protect Alaska's fiscal stability.[134] For example, the Permanent Fund dividend (i.e., the annual payment made to Alaska citizens) is based on a trailing average of the current plus previous four years' Fund Statutory Net Income, thereby

130 Fall 2014 Revenue Sources Book.
131 The State projects that it will fully deplete its reserve funds sometime between FY 2022 and FY 2023.
132 "Executive Summary FY 2015 10-Year Plan," Alaska Office of Management and Budget, December 12, 2013 ("OMB 10-Year Plan").
133 As of FY 2014.
134 OMB 10-Year Plan.

controlling for broad economic swings.[135] The State also funds programs in advance when appropriate, helping to set aside funding for vital programs, and safeguarding them in the event of a subsequent deficit.[136]

In general, the State projects revenue based on where it comes from and how it can be used.[137] The State's revenue can come from funds collected from in-State activities (categorized as petroleum and non-petroleum), funds received from the Federal Government, and interest and payments earned on assets owned by the State. The revenue is then categorized based on how it can be used: as unrestricted revenue or as restricted revenue. The following diagram illustrates how the State characterizes its revenues.

STATE OF ALASKA REVENUE ALLOCATION



Source: Fall 2014 Revenue Sources Book.

135 "How the PFD Amount is Calculated," Alaska Permanent Fund Corporation.
136 OMB 10-Year Plan.
137 Fall 2014 Revenue Sources Book.

The State's current 10-year revenue projections based on these allocations are presented below.

STATE OF ALASKA REVENUE FORECAST BY CATEGORY ($ IN MILLIONS)

	FY 2015E	FY 2016E	FY 2017E	FY 2018E	FY 2019E	FY 2020E	FY 2021E	FY 2022E	FY 2023E	FY 2024E
Unrestricted Revenue										
Unrestricted General Fund Revenue										
Petroleum Revenue	$2,019	$1,636	$3,070	$3,678	$4,175	$4,197	$3,948	$3,858	$3,823	$3,725
Non-petroleum Revenue	502	528	539	550	554	561	569	572	583	590
Investment Revenue	30	32	48	63	79	95	111	126	142	158
Federal Revenue	0	0	0	0	0	0	0	0	0	0
Total Unrestricted General Fund Revenue	**$2,552**	**$2,197**	**$3,657**	**$4,292**	**$4,808**	**$4,853**	**$4,628**	**$4,556**	**$4,548**	**$4,473**
Total Unrestricted Revenue	2,552	2,197	3,657	4,292	4,808	4,853	4,628	4,556	4,548	4,473
Memo: Petroleum Revenue as a % of Total Unrestricted Revenue	*79%*	*75%*	*84%*	*86%*	*87%*	*87%*	*85%*	*85%*	*84%*	*83%*
Restricted Revenue										
Designated General Fund Revenue										
Non-petroleum Revenue	$323	$322	$326	$326	$325	$325	$325	$325	$325	$324
Investment Revenue	20	36	36	36	36	36	36	36	36	36
Total Designated General Fund Revenue	**$344**	**$358**	**$362**	**$362**	**$361**	**$361**	**$361**	**$361**	**$360**	**$360**
Federal Revenue										
Petroleum Revenue	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5
Federal Receipts	3,126	3,126	3,126	3,126	3,126	3,126	3,126	3,126	3,126	3,126
Total Federal Revenue	**$3,131**	**$3,131**	**$3,131**	**$3,131**	**$3,131**	**$3,131**	**$3,131**	**$3,131**	**$3,131**	**$3,131**
Other Restricted Revenue										
Petroleum Revenue	$513	$466	$677	$701	$723	$690	$645	$600	$580	$560
Non-petroleum Revenue	229	230	231	232	233	235	236	237	238	240
Investment Revenue	3,319	3,537	3,438	3,368	3,332	3,245	3,233	3,210	3,184	3,180
Total Other Restricted Revenue	**$4,061**	**$4,233**	**$4,346**	**$4,301**	**$4,288**	**$4,170**	**$4,113**	**$4,047**	**$4,002**	**$3,980**
Total Restricted Revenue	**7,536**	**7,722**	**7,839**	**7,794**	**7,781**	**7,662**	**7,605**	**7,539**	**7,494**	**7,471**
Total State Revenue	**$10,088**	**$9,919**	**$11,496**	**$12,086**	**$12,589**	**$12,515**	**$12,233**	**$12,095**	**$12,042**	**$11,945**

Source: Fall 2014 Revenue Sources Book.

Additionally, the following table presents the State's projected uses of its unrestricted revenues, including the drawdown of the SBRF and CBRF, as mentioned above.

PROJECTED USES OF STATE OF ALASKA UNRESTRICTED REVENUES ($ IN MILLIONS)

	FY 2014	FY 2015E	FY 2016E	FY 2017E	FY 2018E	FY 2019E	FY 2020E	FY 2021E	FY 2022E	FY 2023E	FY 2024E
Oil Price and Production											
Fall 2014 Forecast ANS West Coast ($ per barrel)	$107.57	$76.31	$66.03	$93.18	$102.81	$112.00	$117.36	$121.14	$123.87	$129.04	$134.39
Fall 2014 Forecast ANS Production (MMBD)	0.531	0.510	0.524	0.534	0.503	0.473	0.436	0.400	0.369	0.343	0.315
Revenue vs. Spending											
Unrestricted General Fund Revenues	$5,394	$2,573	$2,197	$3,657	$4,292	$4,808	$4,853	$4,628	$4,556	$4,548	$4,473
Unrestricted General Fund Expenses	7,053	6,106	5,835	5,600	5,600	5,600	5,600	5,600	5,600	5,600	5,600
Budget Surplus/(Shortfall)	($1,659)	($3,533)	($3,638)	($1,943)	($1,308)	($792)	($747)	($972)	($1,044)	($1,052)	($1,127)
Reserve Balances											
CBRF Main Account Balance End of Year	$6,058	$2,622 [138]	$2,783	$2,236	$1,675	$2,935	$2,269	$1,365	$365	$0	$0
CBRF Subaccount Balance End of Year	6,722	6,968	3,546	2,426	1,884	0	0	0	0	(613)	(1,740)
CBRF Total	$12,780	$9,590	$6,329	$4,662	$3,558	$2,935	$2,269	$1,365	$365	($613)	($1,740)
SBRF Balance End of Year	$3,052	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Reserves	**$15,832**	**$9,590**	**$6,329**	**$4,662**	**$3,558**	**$2,935**	**$2,269**	**$1,365**	**$365**	**($613)**	**($1,740)**

Source: State of Alaska preliminary 10-year budget forecast (dated December 2014).

138 Includes ~$3 billion pension fund transfer.

2. Revenue Sources—Detail

a. Unrestricted Revenue

Revenue classified as unrestricted by the State is defined as "available to fund general state activities and capital projects." In FY 2014, unrestricted revenue comprised $5.4 billion (31%) of total State revenue. The table below details the State's forecast for FY 2015 – FY 2024. Unrestricted revenue is expected to decline over the period as production of Alaska North Slope crude oil declines and an increased supply of oil worldwide drives prices down. Non-petroleum unrestricted revenues include taxes collected from non-petroleum related activities, excise taxes, consumption taxes, charges for services, fines, forfeitures, licenses, permits, rents, royalties and earnings on the General Fund and SBRF.[139]

Additionally, the following table presents the State's projected unrestricted general fund revenue, including its unrestricted petroleum revenue, non-petroleum revenue and investment revenue, as mentioned above.

STATE OF ALASKA 10-YEAR FORECAST OF TOTAL UNRESTRICTED GENERAL FUND REVENUE ($ IN MILLIONS)

	FY 2015E	FY 2016E	FY 2017E	FY 2018E	FY 2019E	FY 2020E	FY 2021E	FY 2022E	FY 2023E	FY 2024E
Unrestricted Petroleum Revenue	$2,019	$1,636	$3,070	$3,678	$4,175	$4,197	$3,948	$3,858	$3,823	$3,725
Unrestricted Non-petroleum Revenue	502	528	539	550	554	561	569	572	583	590
Unrestricted Investment Revenue	30	32	48	63	79	95	111	126	142	158
Total Unrestricted Revenue	**$2,552**	**$2,197**	**$3,657**	**$4,292**	**$4,808**	**$4,853**	**$4,628**	**$4,556**	**$4,548**	**$4,473**
Percentage from Oil	*79%*	*75%*	*84%*	*86%*	*87%*	*87%*	*85%*	*85%*	*84%*	*83%*

Source: Fall 2014 Revenue Sources Book.

b. Restricted Revenue

Revenue classified as restricted must be used for a specific purpose and includes funds restricted by the State constitution, federal law, trust or debt restrictions or customary practice. The largest sources of restricted revenues include restricted royalties, restricted investment income and federal revenue.

Restricted royalties track changes in price, transportation costs and production of related resources. Lower oil production could provide a drag on restricted royalties in the future. Restricted investment income relates to earnings from the Permanent Fund, CBRF and designated parts of the General Fund on their respective investments, and in FY 2014 was $7.9 billion, or 67% of total restricted revenue. Federal revenue is exclusively restricted and includes highway, medical care, education and other purposes. The State is typically required to contribute to the same projects for which it receives federal funding—for instance, in FY 2014, the State spent $641 million and received

[139] Fall 2014 Revenue Sources Book.

$2.5 billion to fund federal revenue-specific projects. Historically, the State has utilized approximately 70% – 80% of its annual appropriated federal funding.[140]

B. Balance Sheet

1. Debt

The State of Alaska currently enjoys a "triple-A" rating from all three major credit rating agencies (Standard & Poor's[141], Moody's[142] and Fitch[143]). Rating agency reports have commended the State's conservative financial management, citing a low debt burden and increased reserve amounts to offset any unanticipated shifts in the price or production of oil. While the State currently relies on North Slope oil production for revenues, there are long-term alternatives being considered in natural gas (e.g., the Project, ASAP) and mineral production-related revenue, potential implementation of a State-wide broad-based tax, and the potential use of earnings of the Permanent Fund to offset costs of government services. The State's current debt position is very conservative[144] and, as a result, the State has maintained a level of flexibility in funding its capital projects that is not experienced by many other states.[145]

The conservative nature of the State's debt practices is evidenced by its relatively low level of debt service as a percentage of unrestricted general fund revenue. While the current State policy is designed to limit this ratio to 8.0%, for the last ten years the State has remained below 5.0% and achieved 3.3% for fiscal year 2013.[146]

In addition to the low level of debt service as a percentage of unrestricted general fund revenue, another metric demonstrating the conservative debt position of the State is the trajectory of its general obligation debt retirement. Approximately 70% of the current general obligation debt outstanding is expected to amortize over the next 10 years, allowing for increased financial flexibility.[147]

The State has traditionally utilized long-term fixed rate debt in relation to its general obligation bond issuances. This, in turn, has resulted in limited exposure to floating or variable rate debt, swaps or other derivative products used to hedge interest rate risk. While it is recognized that agencies of the State use variable rate debt and derivative products, limited direct exposure exists for the State itself, and the risks associated with such products are generally not found in the State's general obligation bond indebtedness.

140 Fall 2014 Revenue Sources Book.
141 "Alaska Appropriations; General Obligation; Moral Obligation," Standard & Poor's, January 7, 2013.
142 "Moody's revises Alaska's outlook to negative after oil price plunge; affirms Aaa GO rating," Moody's, December 19, 2014.
143 "State of Alaska General Obligation Bonds Full Rating Report," Fitch Ratings, April 16, 2013.
144 FirstSouthwest analysis.
145 The State's conservative position has been enhanced by its decision to employ a "pay-as-you-go" strategy as a primary source of capital.
146 FirstSouthwest analysis.
147 FirstSouthwest analysis.

The State's ability to fund capital projects with current revenues has played a significant role in the relatively low level of general obligation debt for the State. The reliance on current revenues has limited the State's need for bond issuance as a funding source and, as a result, has allowed the State to maintain a flexible debt profile.

a. State Bonding Capacity Considerations

In light of the State's relatively conservative debt practices discussed above, the State may potentially have capacity to issue additional debt. A primary consideration that must be evaluated in calculating the amount of any additional capacity is the impact of incremental debt on the State's credit rating. Additionally, the State must decide whether it is willing to accept potential downgrades of its credit rating to gain the benefit of additional debt capacity.

The State of Alaska's debt service as a percentage of total budget/revenues is the second-lowest among all states, at 1.2% in 2013.[148] This ratio ranges from 0.9% (Iowa) to 8.2% (Delaware) for "triple-A" rated States, which makes it difficult to judge at exactly what level the State could expect to receive a downgrade; only four states have ratios above 10%: Connecticut (Aa3), Massachusetts (Aa1), Illinois (A3) and New York (Aa2). However, for other debt ratios (e.g., debt as a percentage of GDP, personal income, etc.), the State is much closer to or above the medians for all states.

Lazard has requested that FirstSouthwest perform an analysis that takes the above factors into consideration in order to calculate the State's potential additional borrowing capacity. The methodology and results of this analysis are presented below.

STATE BONDING CAPACITY ANALYSIS[149]

	METHODOLOGY—GENERAL	METHODOLOGY—SCENARIO SPECIFIC	ILLUSTRATIVE RESULTS
SCENARIO 1—STATE MAINTAINS CURRENT "Aaa" RATING	■ All future debt issuances are structured as tax-exempt bonds amortized over 20 years, with level debt service payments ■ Assumed tax-exempt interest rates based on the target rating (3.53% for Aaa, 3.62% for Aa1, 3.70% for Aa2)[150] ■ Annual unrestricted general fund revenues available to pay debt service through 2024 are set at amounts stipulated in the Fall 2014 Revenue Sources Book[151]	■ Debt service in any year cannot exceed the targeted level of **5%** of the prior year's unrestricted general fund revenues	■ State has capacity to issue up to **$2.7 billion** of incremental debt over the next 10 years
SCENARIO 2—STATE IS DOWNGRADED TO "Aa1" RATING		■ Debt service in any year cannot exceed the targeted level of **8%** of the prior year's unrestricted general fund revenues	■ State has capacity to issue up to **$4.7 billion** of incremental debt over the next 10 years
SCENARIO 3—STATE IS DOWNGRADED TO "Aa2" RATING		■ Debt service in any year cannot exceed the targeted level of **10%** of the prior year's unrestricted general fund revenues	■ State has capacity to issue up to **$5.9 billion** of incremental debt over the next 10 years

148 Debt service as a percentage of total budget/revenues is a ratio used by rating agencies, which is different from debt service as a percentage of unrestricted general fund revenue, a ratio mandated by State policy to remain below 8%.
149 FirstSouthwest analysis.
150 I.e., the State's cost of debt would potentially increase with ratings downgrades.
151 If forecasted Project revenues are included in this projection, the State would see its debt capacity increase to $3.8 billion, $6.4 billion and $8.1 billion in Scenario 1, Scenario 2 and Scenario 3, respectively.

As can be seen above, FirstSouthwest's analysis indicates that State has a moderate amount of capacity to issue incremental debt (in this instance, "debt" means general obligation debt and State-supported debt) in the scenario where it maintains its current rating ($2.7 billion) and stays below the 5% target level of debt service as a percentage of unrestricted general fund revenues. However, if the State is willing to take a downgrade to "Aa1", it can still stay under its policy-driven 8% cap on debt service as a percentage of unrestricted general fund revenues and gains an additional $2.0 billion of debt capacity (i.e., the total incremental debt capacity rises to $4.7 billion). Finally, if the State is willing to accept a downgrade to "Aa2", it would see its capacity to issue incremental debt rise to $5.9 billion.[152]

2. Overview of State Funds

The State is responsible for overseeing a variety of different funds that hold the majority of the State's assets. A brief overview of these funds is presented below.

OVERVIEW OF STATE FUNDS

		Description	Asset Allocation	Investment Mandate
PERMANENT FUND		■ Established in 1976; invests a portion[153] of the State's mineral lease rentals, royalties, royalty share proceeds and federal mining revenue-sharing payments and bonuses in income-producing investments ■ Initially intended to steer the State towards better management of the influx of private lease revenue from drilling and exploration activities ■ Since 1982, has paid an annual dividend to Alaska residents (the "Permanent Fund Dividend"); was $1,884 in 2014	■ Fund size: $52.4 billion □ U.S. Bonds: 21% □ International Equity: 18% □ Alternatives: 18% □ Other: 43%	■ Target real return of 5.2% ■ Divided into two subcategories: principal and earnings reserve □ Principal may not be spent, while the earnings reserve, which consists of realized gains from investments as well as unrealized gains, can be spent for any public purpose
OTHER FUNDS	GeFONSI	■ "General Fund and Other Non-segregated Investments" represents a pool of funds managed by the State's Treasury Division	■ Fund size: $4.5 billion □ Liquidity/short-term: 72% □ Intermediate-term: 28%	■ Target return of 2.1% ■ Pooling method reduces liquidity needs and allows for a more aggressive investment mandate
	SBRF	■ General savings fund consisting of appropriations in excess of funds received by the State	■ Fund size: $3.7 billion □ Short-term: 47% □ Intermediate-term: 33% □ Broad Market/FI: 20%	■ Invested in such a way as to "meet immediate expenditure needs" of the State
	CBRF	■ Established in 1990 and funded through resolution of disputes about the amount of certain mineral-related income ■ Consists of a main fund and subaccount	■ Fund size: $10.9 billion ■ Main Account: □ Short-term: 47% □ Intermediate-term: 33% □ Broad Market/FI: 20% ■ Subaccount: □ Domestic Equity: 40% □ Broad Market/FI: 39% □ International Equity: 21%	■ Main Account: □ Expected to return "competitive market rate" ■ Subaccount: □ May invest in higher risk/return asset classes than the Main Account, under the assumption that the funds used would not otherwise be needed for at least five years
	PCE ENDOWMENT FUND	■ The Power Cost Equalization Endowment Fund ("PCE Endowment Fund") was created to provide for affordable electric utility costs for rural Alaska ■ Established in 2001 with funds from the CBRF and proceeds from the sale of a hydroelectric project	■ Fund size: $974 million □ Domestic Equity: 44% □ Broad Market/FI: 33% □ International Equity: 23%	■ Target return of 7.0%
	OTHER	■ Various other funds managed by the State, including the Public School Trust Funds and Retiree Health Insurance Fund	■ Fund size: $1.4 billion □ Various asset allocations	■ Various

Sources: Alaska Constitution, and websites including State Department of Revenue, Alaska Permanent Fund Corporation and Alaska Energy Authority.
Note: FI refers to fixed income. Fixed income securities (e.g., bonds) require the security issuer to make scheduled payments to investors. This is in contrast to equity securities, which generally have no such requirement, albeit equity issuers frequently pay discretionary dividends.

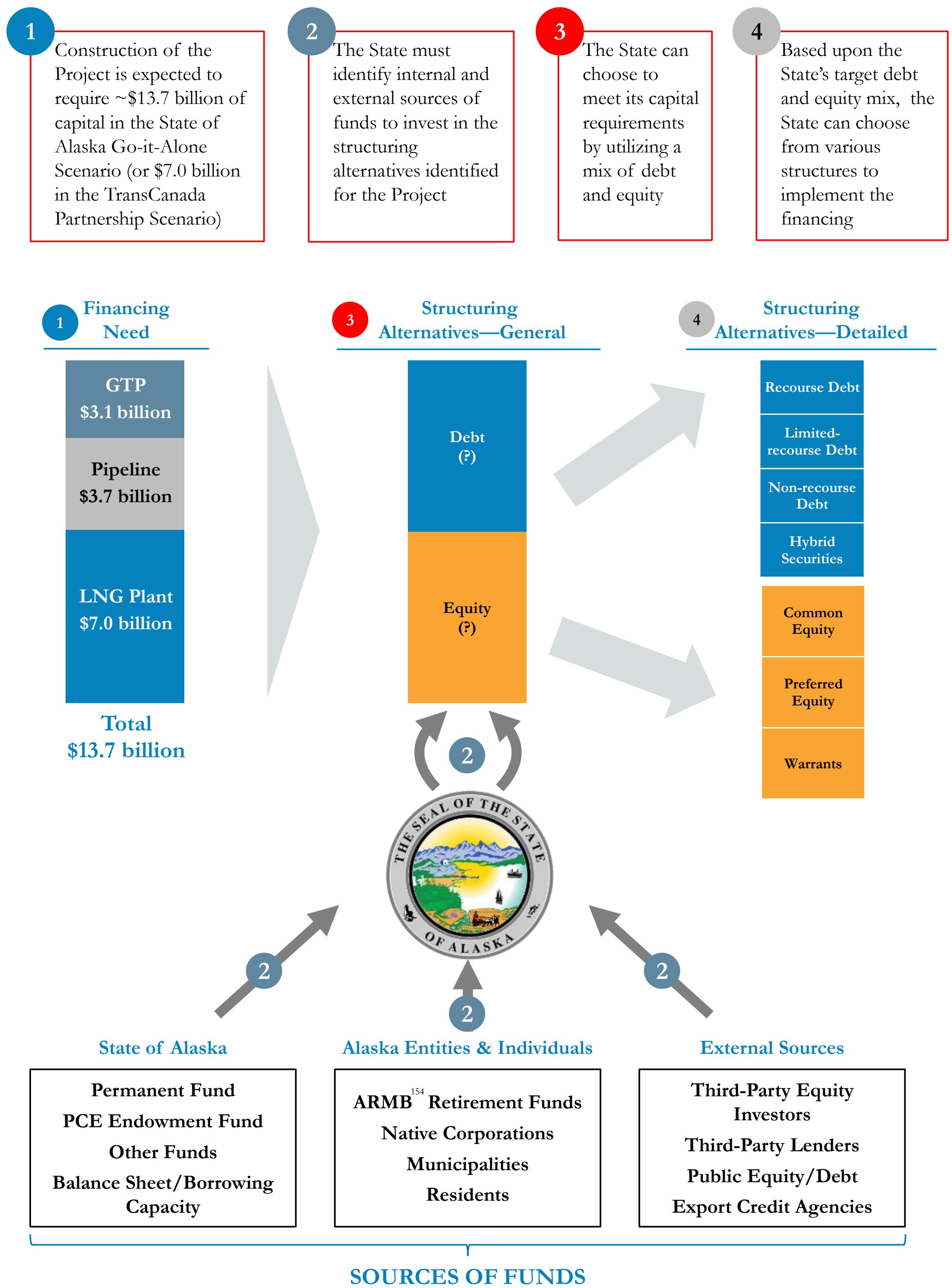
152 If forecasted Project revenues are included in this projection, the State would see its debt capacity increase to $3.8 billion, $6.4 billion and $8.1 billion in Scenario 1, Scenario 2 and Scenario 3, respectively.

153 Specified as 25% for mineral leases issued before circa 1980 and 50% for mineral leases issued after circa 1980.

VI Summary Preliminary Financing Considerations

VI. Summary Preliminary Financing Considerations

The State of Alaska's financing strategy with respect to the AKLNG Project will likely be largely determined by the State's overall Project funding requirement, its available sources of funds and the "optimal" capital structure (e.g., debt/equity mix). These determinations are interrelated and should be evaluated together, as illustrated below.



[154] ARMB denotes Alaska Retirement Management Board.

A. Description of Financing Need

As described earlier, the State must finance its portion of the upfront investment in the Project in order to participate as a 25% owner in the Project and receive future Project cash flows. Based on current forecasts, this financing amount could range from approximately \$7.0 billion (if it pursues the TransCanada Partnership Scenario) to \$13.7 billion (if it pursues the State Go-it-Alone Scenario).[155, 156] These figures are presented below.

STATE OF ALASKA PROJECT INVESTMENT—TRANSCANADA PARTNERSHIP SCENARIO (\$ IN MILLIONS)

	PRE-FEED		FEED			EPC					Total
	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	
GTP	\$-	\$-	\$-	\$-	\$-	\$-	\$-	\$-	\$-	\$-	\$-
Pipeline	-	-	-	-	-	-	-	-	-	-	-
LNG Plant	14	29	61	72	46	954	1,637	1,686	1,390	1,073	6,964
Total	**\$14**	**\$29**	**\$61**	**\$72**	**\$46**	**\$954**	**\$1,637**	**\$1,686**	**\$1,390**	**\$1,073**	
Phase Total	**\$43**		**\$180**			**\$6,741**					**\$6,964**[157]

STATE OF ALASKA PROJECT INVESTMENT—STATE GO-IT-ALONE SCENARIO (\$ IN MILLIONS)

	PRE-FEED		FEED			EPC					Total
	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	
GTP	\$11	\$22	\$46	\$54	\$35	\$415	\$712	\$733	\$604	\$467	\$3,099
Pipeline	11	22	46	54	35	498	854	880	725	560	3,685
LNG Plant	14	29	61	72	46	954	1,637	1,686	1,390	1,073	6,962
Total	**\$35**	**\$73**	**\$153**	**\$180**	**\$116**	**\$1,866**	**\$3,203**	**\$3,300**	**\$2,719**	**\$2,100**	
Phase Total	**\$108**		**\$450**			**\$13,188**					**\$13,745**[158]

Source: Black & Veatch Model, dated February 2014.

The State must consider its total Project investment and the investment required at different phases of development. Given the varying degrees of risk associated with different phases of development and that the majority of the financing need (>95%) comes during the EPC phase, the State may choose to use different sources of financing and financing structures for each of the phases of the Project.

155 Black & Veatch Model, dated February 2014.

156 As discussed above in Section IV.F, under the TransCanada Partnership Scenario, the State is responsible for repaying TransCanada's upfront investment via a return of capital mechanism in the tariff structure.

157 Represents 8% of State's total assets as of FY 2013.

158 Represents 16% of State's total assets as of FY 2013.

B. Sources of Funds

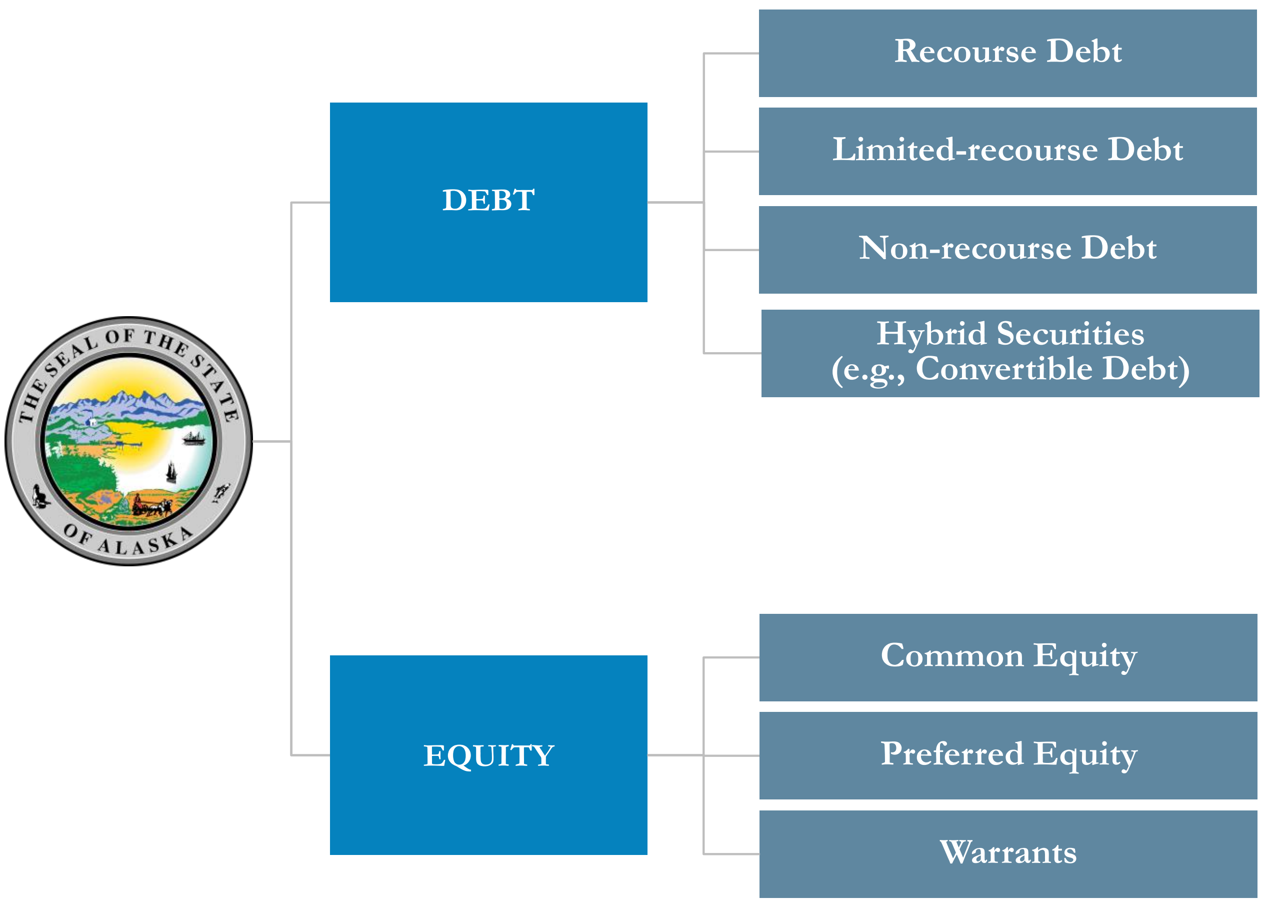
The State has a variety of sources potentially available to fund its portion of the upfront investment in the Project. These sources include those that the State has direct access to, those that could come from Alaska entities and individuals, and those that could come from external sources. A brief overview of the various funding sources is presented below.

		DESCRIPTION
STATE OF ALASKA	PERMANENT FUND	■ The State is responsible for managing $52.4 billion in the Permanent Fund □ Currently broadly invested across public/private debt and equity securities, with 19% currently allocated to real assets[159] □ Potential to allocate substantial capital to the Project, although no precedent exists for direct asset-level investments (generally conducted indirectly via private equity fund managers) □ Potential for the Legislature to allocate Permanent Fund earnings for investment in the Project
	PCE ENDOWMENT FUND	■ The PCE Endowment Fund consists of approximately $1.0 billion invested in domestic and international equities, and fixed income securities □ The PCE Endowment Fund could potentially invest directly in the Project
	OTHER FUNDS	■ Through GeFONSI, CBRF, SBRF and various other funds, the State manages over $19.0 billion □ While the State generally invests these funds in short- to medium-term liquid securities such that they may be drawn upon to pay expenses and fund budget shortfalls, certain funds could potentially invest in longer-term, less liquid assets
	BALANCE SHEET/ BORROWING CAPACITY	■ The State currently has $3.0 billion of long-term debt outstanding □ Revenue bonds, general obligation debt, capital leases, etc. compose this balance □ The State has the capacity to issue incremental debt of $3.8 – $8.1 billion, depending on the State's willingness to accept a rating downgrade[160]
ALASKA ENTITIES AND INDIVIDUALS	ARMB RETIREMENT FUNDS	■ ARMB is responsible for managing $26.6 billion of funds across seven systems □ Currently broadly invested across public/private debt and equity securities □ Potential to allocate capital to the Project given current fund allocation to real assets[161]
	NATIVE CORPORATIONS	■ Alaska's 13 native corporations generated $368 million of net income in 2010[162] □ These native corporations could potentially invest capital in the Project as a means of generating additional income and returning increased dividends to members
	MUNICIPALITIES	■ Alaska municipalities generate revenues via property, sales and severance taxes, and other fees □ While these revenues are generally used to fund operating budgets, municipalities could potentially invest directly in the Project ■ Alaska municipalities currently have $3.2 billion of debt outstanding[163] and generally exhibit strong credit ratings[164] □ Additional debt could be issued by municipalities to fund an investment in the Project
	RESIDENTS	■ Residents of Alaska are also potential investors in the Project □ Alaska residents could potentially elect to designate an amount of their annual Permanent Fund dividend to the Project (dividend was $1,884 per resident in 2014) □ Alaska residents could potentially invest personal funds (e.g., savings) directly
EXTERNAL SOURCES	THIRD-PARTY EQUITY INVESTORS	■ Third-party institutional investors, including infrastructure direct investors (e.g., pension funds, sovereign wealth funds, insurance companies, banks, private equity sponsors, etc.), seek investments with long-term cash flow characteristics
	THIRD-PARTY LENDERS	■ Third-party lenders, including financing banks (e.g., JP Morgan, Bank of America, etc.), could potentially lend to the Project
	PUBLIC EQUITY/DEBT	■ Retail and institutional investors, via brokers and otherwise, make investments in a variety of public debt and equity securities
	EXPORT CREDIT AGENCIES	■ Export credit agencies provide loans to aid in the development of projects that provide their sponsor countries with key imports or exports, such as LNG or other natural resources □ Examples include Japan Bank for International Cooperation ("JBIC") ($126 billion of outstanding loans and guarantees), Korea Ex-Im Bank ($86 billion of outstanding loans and guarantees), Export-Import Bank of the United States ($79 billion of outstanding loans and guarantees)

159 "Asset Allocation," Alaska Permanent Fund Corporation.
160 Per FirstSouthwest analysis in case where Project revenues are considered.
161 ~$3.6 billion currently invested in real assets. However, the amount available to invest in the Project is likely much less, due, in part, to current illiquid investments and investment concentration concerns (i.e., the ARMB would not likely concentrate a substantial portion of its funds on one investment).
162 "Regional Alaska Native Corporations," GAO, December 2012.
163 "Alaska Public Debt," The State of Alaska, January 2014.
164 Moody's.

C. Debt and Equity Structuring Alternatives

Irrespective of the funding source used, the State will need to evaluate the optimal financing structure via which those funds are invested in the Project.[165] In general, the State could structure these funds as either debt or equity interests in the Project. More specifically, a spectrum of structuring alternatives exists for both debt and equity. Each alternative offers different risk and return profiles, as well as other characteristics related to seniority/priority, payout structure, governance rights and other features.[166]



165 The State may also need to consider the overall capital structure of the Project (i.e., how other Project owners have chosen to capitalize their investments in the Project).

166 Structuring alternatives to be discussed in greater detail in Section VII.

D. Other Considerations

The State might consider other alternatives to lower its cost of capital, shift/mitigate risk, or otherwise achieve its financing objectives. These alternatives could include:

	DESCRIPTION
CREDIT SUPPORT	■ The State could provide or access credit support to spread risks posed by the Project to other parties and to lower the Project's cost of capital ■ Potential opportunities for credit support include the following: 　■ State provides a guarantee on debt payments owed by an external Project sponsor 　■ State seeks a guarantee on debt payments owed by the State; such credit support may be provided by, for example, the U.S. Federal Government, multilateral banks, etc. 　■ State or other third parties provide guarantees in the form of a backstop to Project cost overruns ■ Guarantees by financially strong third parties could potentially lower the overall cost of debt associated with financing; however, a guarantee issued by the State could potentially impact the State's balance sheet and credit rating, even if the State is only indirectly obligated on the liability or the risk of triggering funding support is remote
INSURANCE/ RISK MITIGATION	■ The State could purchase insurance to provide downside protection for various aspects of the Project to shift certain risks to third parties ■ Potentially insurable areas include: 　■ Construction Risks: Covers losses or damage to materials, supplies, equipment or temporary structures for general building and engineering purposes, respectively 　■ Delay in Start Up Risk: Covers any delays in the Project's ability to generate revenue in a timely manner 　■ *Force Majeure*: Covers any risks associated with acts of nature (e.g., storms, earthquakes, etc.) 　■ Performance Failure or Design Risk: Covers any losses arising from ineffective design or workmanship 　■ Political Risk: The State could provide contractual assurances that any increases in costs or delays associated with future Alaska political decisions would be borne by the State ■ The greater the likelihood of a claim and the larger the size of that claim dictate the cost of an associated premium paid to an insurer (i.e., insurance against large and likely events would likely be more expensive than insurance against small and unlikely events)
EQUITY/DEBT SYNDICATION	■ The State could syndicate (i.e., market to third parties) its interest in the Project to spread risks posed by the Project to other parties and to provide liquidity to the State at later stages of Project development ■ Potential opportunities for syndications might include: 　■ Debt and/or equity syndication to Alaska individuals, Alaska corporations, or individuals and corporations from outside the State ■ Syndication provides an opportunity to rotate capital out of the Project once specific Project milestones are achieved and the overall Project risk is reduced

VII Overview of Potential Structuring Alternatives

VII. Overview of Potential Structuring Alternatives

The State's interest in the Project would—as a practical, operational/governance and legal matter—likely be facilitated through a separate, standalone entity (herein referred to as the "State Project Company").[167] The State Project Company would be similar to many other companies in that it would be able to issue debt and equity in order to raise funds to pursue investments. The State Project Company, however, would likely be limited to investing only in the AKLNG Project, and would subsequently serve to receive Project revenues, make debt service payments and generally manage the State's investment interest in the Project. Upon formation of the State Project Company, the State would be the sole owner and parent of the entity.

Importantly, the State Project Company would have various funding sources by which it would be capitalized, and various structuring alternatives, or ways in which it could invest in the Project. For example, the Permanent Fund (a funding source) might wish to invest in the State Project Company as a common equity holder (a structuring alternative). Similarly, the State could issue general obligation debt (a funding source) and, with the proceeds, decide to invest in the State Project Company as a non-recourse debt holder (a structuring alternative). The State may choose to fund the State Project Company via multiple funding sources—including Alaska municipalities, individuals and other State entities—and the State Project Company might invest in the Project via multiple structures, none of which are mutually exclusive.

While reading the following sections, which describe in detail the various ways that the State Project Company could potentially finance itself in order to invest in the Project, it is important to consider the relative cost of each of the structuring alternatives presented. The State Project Company's financing cost would likely be a function of many factors, including its capital structure and the Project's position in the development lifecycle. Various debt and equity alternatives have different relative costs, based on specific attributes. For example, non-recourse debt is typically more expensive than recourse debt, because the risk to lenders is higher in a default scenario. Similarly, preferred equity is typically less expensive than common equity, because preferred equity shareholders receive dividends before common equity shareholders receive dividends.

Ultimately, the State Project Company should seek to optimize its capital structure with debt, equity or a combination thereof, based on its priorities, including control and governance rights, operational flexibility and, importantly, cost. The State Project Company's blended financing cost (i.e., its weighted average cost of capital ("WACC")) would be determined based on the relative amounts of debt and equity in its capital structure, and their respective costs. The following illustrates the relative cost of the various debt and equity structuring alternatives, each of which will be further explained in the following sections.

167 An existing State entity could potentially serve as the State Project Company, depending on various legal and structuring considerations to be determined in the future.

ILLUSTRATIVE FINANCING COST—CAPITAL STRUCTURE

Lower Cost ⟵ ⟶ **Higher Cost**

Recourse Debt	Limited-recourse Debt	Non-recourse Debt	Hybrid Securities (e.g., Convertible Debt)	Warrants	Preferred Equity	Common Equity
Illustrative Cost: 4.0% – 10.0% LIBOR[168]+1.25% to LIBOR+7.25%				Illustrative Cost: 10.0% – 15.0%		

- Cost of debt can be estimated prospectively via an analysis of precedent debt issuances
- The cost of debt can vary widely depending on the size of the issuance, the intended use of proceeds, the debt term, the rating of the issuer and whether the debt is tax exempt
  - Appendix A.2 presents cost of debt precedents along each of these parameters

- Hybrid securities typically exhibit costs lower than those for "straight" equity but higher than those for debt, depending on the value of the embedded conversion option

- Cost of equity can be estimated via the capital asset pricing model ("CAPM")
  - CAPM seeks to estimate the required return on a project based on the project's perceived riskiness
  - One way to estimate the riskiness of the Project is to analyze the market-observed riskiness of publicly-traded companies that engage in business that is similar to that of the Project
  - Appendix A.1 contains CAPM analysis for companies engaged in LNG operations, oil and gas production, EPC contracting and pipeline operations

Another determinant of the State Project Company's cost of financing is the perceived riskiness of its projected cash flows. The risk related to the Project's expected cash flows will vary over time. In the early stages of the Project's development lifecycle, financing costs are likely to be highest, due to the perceived risks associated with realization of the Project and, therefore, future Project cash flows. As the Project advances in its development lifecycle, the certainty of future Project cash flows should increase and the perceived risk associated with the Project should decrease accordingly, leading to lower financing costs.

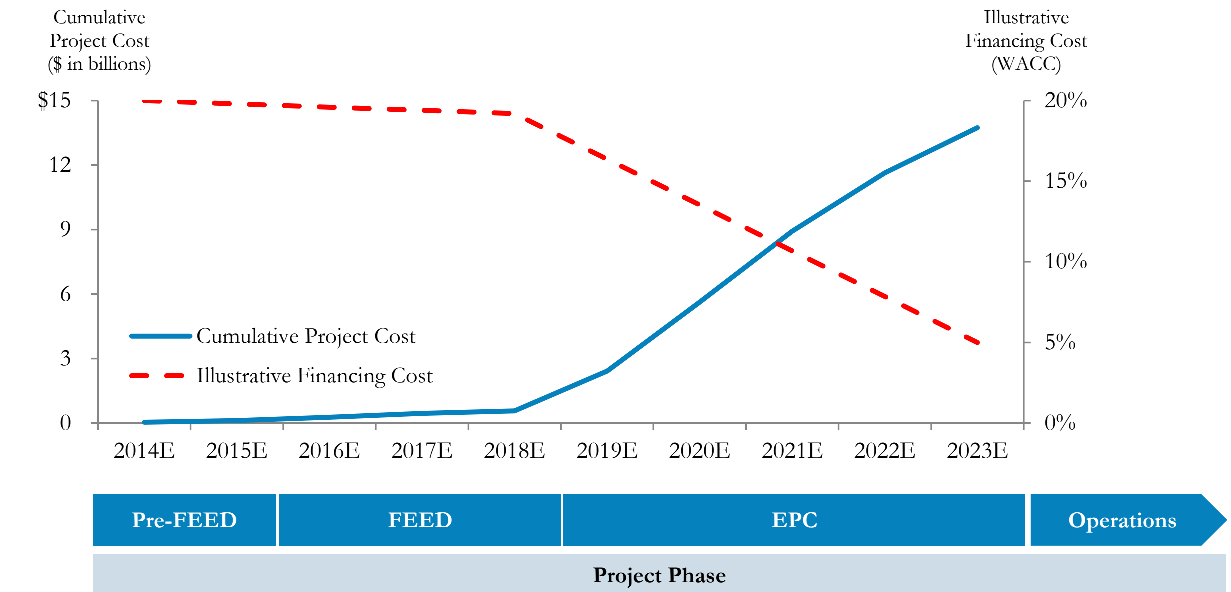
As a practical matter, lenders would likely be reluctant to finance the Project in its early stages (absent some direct credit support/guarantee from the State or others), requiring the State Project Company to structure its initial investment as a form of equity. As the Project advances, permitting is completed, commercial arrangements are secured and construction is ready to commence, lenders would likely be more able to provide debt financing and the cost of securing third party financing should also be more competitive.

168 The London Interbank Offered Rate ("LIBOR" or "L") is a benchmark rate that banks charge each other for short-term loans. LIBOR is often used in determining the interest rate for floating-rate debt issuances. As of December 31, 2014, the 3-month LIBOR rate was 0.26%.

Similarly, as the Project advances, the value of the State's ownership interest would likely increase. As the Project reaches commercial operation and is fully "de-risked", the State may choose to monetize a portion of its ownership interest (via issuing debt, selling equity[169] or otherwise) in order to diversify its investment, pursue other relevant investment opportunities or allocate capital to other State priorities.

The following chart illustrates the relationship between the cost of financing and Project phase.

ILLUSTRATIVE FINANCING COST—PROJECT LIFECYCLE



Note: Cumulative Project cost shown for State Go-it-Alone scenario.

169 The State could also monetize its ownership interest in the Project via alternative structures, which include master limited partnerships and YieldCos, among others.

A. Debt

1. Recourse Debt

DESCRIPTION	■ The State Project Company could issue recourse debt that may be secured by the revenue/assets of the State Project Company, but that ultimately has full recourse to the State
	  ■ Recourse debt is a type of a loan that has full recourse to the borrower's parent entity
	■ The lender would be entitled to principal and interest payments based on a negotiated amortization schedule and interest rate, respectively
	  ■ Failure to make payments on time could result in a default scenario
	■ In a default scenario, the State (as the parent of the State Project Company) would be fully liable for principal repayment
	  ■ The lender's recourse to the State would not be limited
	■ Recourse debt could potentially be accompanied by restrictive covenants, which would limit the actions of the State Project Company
	  ■ Categories of covenants include maintenance covenants and incurrence covenants; violation of covenants may result in a default scenario
	    – A maintenance covenant might require the State Project Company to maintain or achieve a certain level of financial performance to avoid default (e.g., a covenant requiring the State Project Company to maintain a certain ratio of Project cash flow to scheduled debt service)
	    – Incurrence covenants might prohibit the State Project Company from undertaking certain actions (e.g., incurring additional debt or making a restricted payment)
	■ A lender's claim on the State Project Company would expire after repayment of the initial loan principal
	  ■ A lender's recourse to the State would expire after the initial loan principal was repaid

BENEFITS	■ Less expensive than equity alternatives; additionally, least expensive form of debt alternatives ■ No dilution of the State's ownership or control interest in the State Project Company ■ Lenders have a defined interest in the State Project Company, limited to principal and interest payments ■ Debt service requirements are generally very predictable and stable over time and may therefore be structured in accordance with the State Project Company's investing needs and expected future revenues

CONSIDERATIONS	■ State Project Company creditors have full recourse to the State in the event of a default scenario
	  ■ Potentially significant impact on the State's credit rating
	■ Restrictive covenants reduce operational flexibility for the State Project Company
	■ Recourse debt can create conflicts of interest among State Project Company stakeholders
	  ■ Lenders typically favor more conservative management choices, while equity investors favor riskier management choices with the potential for a higher payout
	■ Potential for financial distress (not limited to Project level)

SUMMARY ASSESSMENT	■ Riskiest debt alternative for the State Project Company; full recourse to the State and potentially significant impact on the State's credit rating ■ Relatively less expensive than other debt alternatives ■ Allows the State to maintain its undiluted ownership and control interest in the State Project Company

2. Limited-recourse Debt

DESCRIPTION	■ The State Project Company could issue limited-recourse debt that may be secured by the revenue/assets of the State Project Company, but that ultimately has some amount of recourse to the State
	  ■ Limited-recourse debt is a type of a loan that has recourse to the borrower's parent entity, but only to a specified amount and generally only for a specified period of time
	■ The lender would be entitled to principal and interest payments based on a negotiated amortization schedule and interest rate, respectively
	  ■ Failure to make payments on time could result in a default scenario
	■ In a default scenario, the State (as the parent of the State Project Company) would be liable (only up to a certain amount) for principal repayment
	  ■ The lender's recourse to the State would generally be limited to a negotiated amount (e.g., 50% of the original loan amount) and time period (e.g., until the Project has reached operations)
	■ Limited-recourse debt could potentially be accompanied by restrictive covenants, which would limit the actions of the State Project Company
	  ■ Categories of covenants include maintenance covenants and incurrence covenants; violation of covenants may result in a default scenario
	    – A maintenance covenant might require the State Project Company to maintain or achieve a certain level of financial performance to avoid default (e.g., a covenant requiring the State Project Company to maintain a certain ratio of Project cash flow to scheduled debt service)
	    – Incurrence covenants might prohibit the State Project Company from undertaking certain actions (e.g., incurring additional debt or making a restricted payment)
	■ A lender's claim on the State Project Company would expire after repayment of the initial loan principal
	  ■ A lender's recourse to the State would also expire at this time, unless negotiated to be earlier per the above (e.g., when the Project has reached operations)

BENEFITS	■ Less expensive than equity alternatives
	■ Limited recourse to the State in the event of a State Project Company default
	  ■ Potential for only moderate impact on the State's credit rating
	■ No dilution of the State's ownership or control interest in the State Project Company
	  ■ Lenders have a defined interest in the State Project Company, limited to principal and interest payments
	■ Debt service requirements are generally very predictable and stable over time and may therefore be structured in accordance with the State Project Company's investing needs and expected future revenues

CONSIDERATIONS	■ More expensive than recourse debt, albeit less expensive than non-recourse debt ■ Restrictive covenants reduce operational flexibility for the State Project Company ■ Limited-recourse debt can create conflicts of interest among State Project Company stakeholders ■ Lenders typically favor more conservative management choices, while equity investors favor riskier management choices with the potential for a higher payout ■ Potential for financial distress (not limited to Project level)

SUMMARY ASSESSMENT	■ Somewhat risky debt alternative for State Project Company; only limited recourse to the State and potential for only moderate impact on the State's credit rating ■ "Middle of the road" in terms of cost vs. other debt alternatives; still less expensive than equity alternatives ■ Allows the State to maintain its undiluted ownership and control interest in the State Project Company

3. Non-recourse Debt

DESCRIPTION	■ The State Project Company could issue non-recourse debt[170] secured by the revenue/assets of the State Project Company
	  ■ Non-recourse debt is a type of a loan that is secured by specific assets or cash flows (i.e., collateral)
	■ The lender would be entitled to principal and interest payments based on a negotiated amortization schedule and interest rate, respectively
	  ■ Failure to make payments on time could result in a default scenario
	■ In a default scenario, the State (as the parent of the State Project Company) would not be liable for principal repayment
	  ■ The lender's only recourse would be the revenue/assets used as collateral for the loan
	■ Non-recourse debt could potentially be accompanied by restrictive covenants, which would limit the actions of the State Project Company
	  ■ Categories of covenants include maintenance covenants and incurrence covenants; violation of covenants may result in a default scenario
	    – A maintenance covenant might require the State Project Company to maintain or achieve a certain level of financial performance to avoid default (e.g., a covenant requiring the State Project Company to maintain a certain ratio of Project cash flow to scheduled debt service)
	    – Incurrence covenants might prohibit the State Project Company from undertaking certain actions (e.g., incurring additional debt or making a restricted payment)
	■ A lender's claim on the State Project Company would expire after repayment of the initial loan principal

BENEFITS	■ Less expensive than equity alternatives
	■ No recourse to the State in the event of a State Project Company default
	  ■ Minimal (if any) impact on State's credit rating
	■ No dilution of the State's ownership or control interest in or control of the State Project Company
	  ■ Lenders have a defined interest in the State Project Company, limited to principal and interest payments
	■ Debt service requirements are generally very predictable and stable over time and may therefore be structured in accordance with the State Project Company's investing needs and expected future revenues

CONSIDERATIONS	■ More expensive than other debt alternatives ■ Restrictive covenants reduce operational flexibility for the State Project Company; these covenants are typically more restrictive when attached to non-recourse debt than other debt or equity alternatives ■ Non-recourse debt can create conflicts of interest among State Project Company stakeholders ■ Lenders typically favor more conservative management choices, while equity investors favor riskier management choices with the potential for a higher payout ■ Potential for financial distress (albeit limited to Project level)
SUMMARY ASSESSMENT	■ Least risky debt alternative for State Project Company; no recourse to the State and potentially minimal impact on the State's credit rating ■ More expensive than other debt alternatives; less expensive than equity alternatives ■ Allows the State to maintain its undiluted ownership and control interest in the State Project Company

[170] Non-recourse debt is the debt structure most commonly associated with project finance.

4. Hybrid Securities (e.g., Convertible Debt)[171]

DESCRIPTION	■ The State Project Company could issue debt that carries the right to be converted into common shares ■ Convertible debt is a type of "hybrid security" (i.e., one which exhibits characteristics of both debt and equity, depending upon conversion of an underlying option) ■ The option to convert debt principal into common shares rests with the holder ■ The debt would convert at a negotiated exchange ratio (e.g., a certain amount of principal would be worth a certain number of shares) set when the convertible debt is issued – Requires the State Project Company to have a view on the value of its common shares at a future conversion date ■ The option to convert generally expires at the maturity of the debt, although certain types of convertible debt have mandatory conversion and other specialized features ■ Prior to conversion, convertible debt would exhibit the attributes of the debt alternatives discussed above; following conversion, convertible debt would exhibit the attributes of common equity ■ If a conversion option is exercised, common shares of the State Project Company would not expire or mature
BENEFITS	■ Less expensive than equity alternatives, but more expensive than debt alternatives ■ High level of structuring flexibility allows matching of State Project Company and investor goals ■ Attractive to a wider range of investors given the debt and equity features ■ Exhibits the benefits of debt alternatives prior to conversion and the benefits of common equity following conversion ■ Could be beneficial if the State Project Company prefers debt attributes in the near term
CONSIDERATIONS	■ Complexities associated with calculating future value of State Project Company when setting exchange ratio upon convertible debt issuance ■ Miscalculations could result in not receiving adequate proceeds upon conversion ■ Exhibits the considerations of debt alternatives prior to conversion and the considerations of common equity following conversion ■ Could be detrimental if the State Project Company prefers equity attributes in the near term ■ Potentially limited market for convertible debt
SUMMARY ASSESSMENT	■ A type of security that blends the characteristics of debt and equity, thereby producing a more expensive financing choice than other debt alternatives, but a less expensive financing choice than equity alternatives ■ Well-developed area of the capital markets, but more complex than other financing alternatives; in some cases, market for investors can be relatively limited ■ Allows the State Project Company to access a wide range of potential investors

[171] Features of common equity described in this section are presented in greater detail in Section VII.B.1.

B. Equity

1. Common Equity

DESCRIPTION	■ The State Project Company could issue common stock to investors[172]
	  ■ Common stock represents the most basic form of ownership in an entity
	■ Individual units, or shares, of common stock would be issued based on the size of investment and the value of the State Project Company (i.e., the value of the State's interest in the Project)[173]
	■ Common shareholders would be entitled to a residual claim on all assets of the State Project Company, following distributions to any debt holders and preferred equity holders
	  ■ Common shareholders would realize a return on their investment via dividends from the State Project Company (i.e., in each operating period, the State Project Company's excess cash flows would be shared among the shareholders based on the number of shares owned)
	  ■ Common shareholders could also realize a return via appreciation in the value of their shares
	■ Individual shares would entitle holders to the right to vote on key State Project Company decisions
	  ■ In certain cases, different classes of shares could represent a different number of votes (e.g., Class A shares might represent 10 votes, while Class B shares might represent 1 vote)
	■ Common shares of the State Project Company would not expire or mature

BENEFITS	■ Relatively more equity in the Project could provide the State with greater flexibility with respect to operating the State Project Company or otherwise, as the Project would be less burdened by required debt service payments (principal and interest) ■ The State Project Company would likely make dividend payments to common shareholders; however, the frequency and amount of these payments could vary ■ Long-term view of common shareholders could align with that of State and State Project Company ■ Common shareholders have no recourse to the State ■ Structure of Class A and Class B voting shares could allow the State to retain "control" of the State Project Company while maximizing external equity funding sources ■ The State, as a potential common stock investor in the State Project Company, would be able to share in all of the benefits of ownership (e.g., potential for outsized returns, governance rights, etc.)
CONSIDERATIONS	■ Miscalculation of State Project Company value when issuing shares could result in not receiving adequate proceeds for share issuances ■ Potential dilution of the State's ownership interest in and control of the State Project Company in cases where common equity is sold to third-party investors ■ More expensive than debt alternatives ■ Greater potential complexity associated with the tracking of multiple shareholders and related rights

SUMMARY ASSESSMENT	■ At a minimum, the State Project Company must have some amount of common stock, representative of the entity's ownership (i.e., the State prior to incremental common stock issuance) ■ More expensive than debt alternatives; however, may facilitate optimal capital structure and structuring approaches, which could minimize control and other effects of equity issuances ■ The sale of equity to third parties would result in the dilution of the State's ownership in and control of the State Project Company

172 Shares could potentially be issued via an initial public offering ("IPO"). An IPO could potentially occur late in Project development, when State Project Company cash flows are more certain. Existing equity holders (e.g., the State) could choose to sell or retain some or all of their shares through the IPO. IPOs have several benefits in addition to those listed above, including the potential for the State to monetize some or all of its ownership interest in the State Project Company, access a broad investor base, and provide a conventional way for Alaska municipalities, individuals and other State entities to invest in the Project. However, an IPO would also be associated with additional compliance, reporting and operating costs.

173 In certain situations, limitations on the number and type of potential shareholders may exist.

2. Preferred Equity

DESCRIPTION	■ The State Project Company could issue preferred equity to investors
	  ■ Preferred equity represents an ownership interest with debt-like attributes
	■ Shares of preferred equity would be issued based on the size of investment and the value of the State Project Company[174]
	■ Preferred shareholders would be entitled to a claim on the assets of the State Project Company, but generally only up to the value of their initial investment (the "par value")
	  ■ Preferred shareholders would realize a return on their investment via a negotiated fixed dividend payment from the State Project Company that is distributed after all payments are made to debt holders (i.e., principal and interest payments), but before any payments are made to common equity shareholders
	    – Failure to make dividend payments on time would not result in a default scenario (as it would in the case of a missed payment for debt alternatives); however, unpaid dividends generally accrue and must be paid out (with interest) prior to any future dividends to common equity shareholders
	  ■ Preferred shareholders could also realize a return via appreciation in the value of their shares, albeit to a lesser extent than for common shareholders
	■ Unlike common shares, preferred shares generally do not entitle holders to the right to vote on key State Project Company decisions, unless specifically structured to do so
	■ Preferred shares are typically issued in blocks, and can be structured to accommodate varying investor needs (e.g., level of seniority, convertibility into common shares, ability to participate in earnings upside, etc.)
	■ Preferred shares of the State Project Company would not expire or mature, but could be callable (i.e., able to be repurchased by the State Project Company at a premium to par value)

BENEFITS	■ Relatively more equity in the Project could provide the State with greater flexibility with respect to operating the State Project Company or otherwise, as the Project would be less burdened by required debt service payments (principal and interest)
	  ■ The State Project Company would still be required to make fixed dividend payments to preferred shareholders, but would not be at risk of a default scenario in the event of nonpayment
	■ Long-term view of preferred shareholders could align with that of the State and State Project Company
	  ■ High level of structuring flexibility allows matching of State Project Company and investor goals
	■ Preferred shareholders have no recourse to the State
	■ No dilution of the State's ownership interest in the State Project Company
	■ The absence of voting rights would allow the State to retain control of the State Project Company
	■ Callable feature gives the State Project Company the option to reduce fixed dividend payments

CONSIDERATIONS	■ Miscalculation of State Project Company value when issuing shares could result in not receiving adequate proceeds for share issuances ■ More expensive than debt alternatives, albeit less expensive than common equity ■ Greater potential complexity associated with the tracking of multiple shareholders and related rights

SUMMARY ASSESSMENT	■ Preferred equity is a debt-like equity security that would allow the State Project Company to structure its financing in a way that likely does not impact the State's credit rating ■ More expensive than debt alternatives; however, preferred stock is less expensive than common equity and preserves for the State operational flexibility and control/governance rights ■ Allows the State to maintain its undiluted ownership in and control of the State Project Company

[174] In certain situations, limitations on the number and type of potential shareholders may exist.

3. Warrants

DESCRIPTION	■ The State Project Company could issue rights to investors to buy common shares of the State Project Company at a later date, for an upfront payment (warrant premium)
	  ■ A warrant represents a right to buy common shares in an entity at a set price
	■ The option to exercise the warrant (i.e., to buy common shares) rests with the holder
	  ■ The price that the warrant holder would be required to pay for common shares (i.e., the exercise price) would be negotiated and set when the warrant is issued
	    – This exercise price would typically be "out-of-the-money" at the time of warrant issuance, which means that it would be higher than the currently implied value of a common share; as the value of the State Project Company increases with time and exceeded the exercise price, the warrant holder would likely exercise their right to purchase common shares (at the exercise price)
	    – Requires the State Project Company to have a view on the value of its common shares at a potential future warrant exercise date
	  ■ The option to exercise the warrant would expire at a negotiated expiration date
	■ Prior to exercise, warrants would have minimal, if any, impact on the State Project Company; following exercise, warrants would exhibit the attributes of common equity
	■ If the warrant is exercised, common shares of the State Project Company would not expire or mature

BENEFITS	■ Allows the State Project Company to receive an upfront premium without any immediate equity dilution ■ Potentially less expensive than other equity alternatives, as the State can raise capital without any immediate payments ■ Warrants could potentially be added as a "sweetener" to other securities (e.g., debt or preferred equity), to secure more favorable terms (e.g., lower interest or dividend payments, fewer covenants, etc.) ■ Exhibits the benefits of common equity following exercise ■ Could be beneficial if the State Project Company prefers equity attributes in the long term

CONSIDERATIONS	■ Potentially difficult to raise a significant amount of capital
	■ More expensive than debt alternatives, albeit less expensive than common equity
	■ Complexities associated with calculating future value of State Project Company when setting exercise price upon warrant issuance
	  ■ Miscalculations could result in not receiving adequate proceeds upon exercise
	■ Exhibits the considerations of common equity following exercise
	  ■ Could be detrimental if the State Project Company prefers equity attributes in the near term

SUMMARY ASSESSMENT	■ Allow the State Project Company to raise some level of capital while deferring any potential ownership/control dilution ■ Potentially preferable to common equity, depending on the exercise price, scope and benefits to other financing efforts

VIII Preliminary Selected Evaluative Criteria

VIII. Preliminary Selected Evaluative Criteria

The Final Report will provide specific analysis and recommendations with respect to the Project funding sources and financing alternatives[175] available to the State. The various funding sources and financing alternatives will be evaluated against the following criteria, among others, to develop a recommended financing approach for the State:

	DESCRIPTION
POTENTIAL IMPACT ON DEBT CAPACITY/ OPPORTUNITY COST	■ How does the proposed financing alternative potentially limit the State's ability to issue debt or allocate funds to other priorities? ▪ The State has a finite capacity to issue debt, and to the extent that it wishes to issue debt for other purposes, this capacity may be limited depending on how much debt is issued for the Project ▪ The State's funds (e.g., the Permanent Fund) invest in a variety of different securities; diverting dollars to invest in the Project means that these dollars are not available for other fund investments
POTENTIAL IMPACT ON ALASKA CREDIT RATING	■ How does the proposed financing alternative impact the State's credit rating? ▪ Increasing the amount of State debt could potentially result in rating agency downgrades ▪ A decrease in the State's credit rating could constrain future efforts by the State to access the capital markets and could raise the State's overall cost of debt
KEY RISKS	■ How much/what types of key risks are involved with respect to the State undertaking the proposed financing alternative? ▪ Potential for default, financial distress and loss of operational flexibility for debt structuring alternatives ▪ Potential for the State to lose all or a portion of its investment in the Project ▪ Potential for lenders to have recourse to State assets
COST	■ What is the potential cost of securing the financing and providing a return to debt and equity investors? ▪ Interest rate for funding alternatives and debt structuring ▪ Required return for funding alternatives and equity structuring ▪ Issuance, structuring and other fees (e.g., payments to underwriters, lawyers, financial advisors, etc.)
EXECUTION FLEXIBILITY/ FEASIBILITY	■ How difficult will it likely be for the State to execute its preferred financing structure? ▪ Certain types of financing structures are easier to implement than others, including with respect to facilitating investment participation by State residents, corporations and municipalities ▪ Certain types of funding sources are more accessible than others ▪ Certain provisions (e.g., debt covenants) can potentially be restrictive and limit the State's flexibility
ALIGNMENT OF INTERESTS AMONG KEY PARTIES	■ Are the interests of the various key parties aligned? ▪ Certain financing alternatives and/or funding sources may introduce Project misalignment, conflicts of interest or other forms of dysfunction for sponsors

175 Inclusive of any potential terms and conditions.

IX Recommended Next Steps

IX. Recommended Next Steps

In preparation for the delivery of the Final Report in Fall 2015, Lazard will focus on the following areas of analysis and interaction, among others:

- Participation in State legislative session during Spring 2015
- Continued monitoring of global LNG market dynamics
  - Update of Black & Veatch Model to reflect, among other items, current commodity pricing environment[176]
- Continued monitoring of Project developments (e.g., offtake agreements, partnership agreement, etc.) and potential impacts on analysis of financing alternatives
- Further analysis of potential sources of funds
  - Interaction with various State and external fund providers to gauge interest in Project participation
  - Identification of preferred sources of funds via analysis and interaction with key stakeholders, including the Alaska Legislature
- Further analysis of potential structuring alternatives
  - Identification of preferred structuring alternatives via analysis and interaction with key stakeholders, including the Alaska Legislature
- Further refinement of evaluative criteria
- Formation of potential financing alternatives (i.e., combinations of sources of funds and structuring alternatives)
- Analysis of implementation issues associated with potential financing alternatives
  - Legislative
  - Regulatory
  - Legal
  - Execution
  - Other
- Assessment of financing alternatives against evaluative criteria
- Identification of optimal financing alternatives via iterative process (i.e., in consideration of evaluative criteria, implementation issues and other factors)
- Drafting of Final Report
  - Continued iteration and interaction with the Department of Revenue and State advisors

[176] Current Black & Veatch Model is dated February 2014.

X Preliminary Conclusions and Observations

X. Preliminary Conclusions and Observations

The State has determined that a direct investment in a large-scale LNG export project should be an important part of Alaska's fiscal future. While declining Alaska production and global oil prices threaten to create significant budget shortfalls in the near term (the State expects to deplete its current $15 billion budget reserve funds by 2022/2023), the Project has the potential to provide a much needed new revenue source that could help to support the State's budget. Numerous features of the global LNG market, together with factors specific to the Project, support the investment, including projected demand growth in Pacific Rim countries, the State's strategic access to these markets and the quality and abundance of the State's natural gas reserves.

Given the State's determination to pursue a large-scale LNG export project, the State should consider a variety of factors as it determines how it could potentially finance an endeavor of this magnitude (as much as $13.7 billion would be required under the State's currently contemplated 25% ownership stake). For example, there exist a number of funding sources that can be called upon by the State to fund its investment in the Project; these funding sources include those under the State's control (e.g., the Permanent Fund), those of Alaska entities and individuals and those of external investors. Additionally, the State must consider the equity and debt capitalization of its investment in the Project and what types of structures (e.g., non-recourse debt, common equity, etc.) are most beneficial, while also considering a number of potential evaluative criteria. In general, the State should seek an "optimal" structure that limits its overall cost of financing while also taking into account other evaluative criteria, including impact on the State's debt capacity and credit rating, risk, feasibility and the alignment of interests among key parties.

Over the next several months, in preparation for the delivery of the Final Report in Fall 2015, Lazard will further analyze the concepts introduced in this Report and will work with various stakeholders (including the Department of Revenue, other State advisors and the Alaska Legislature) to identify and formulate optimal financing recommendations for the State's participation in the Project.

XI Appendix Materials

XI. Appendix Materials

A. Preliminary Cost of Capital Data

The State Project Company's weighted average cost of capital would be determined based on the relative amounts of debt and equity in its capital structure, and their respective costs. An illustrative implied cost of equity can be derived via the CAPM, which utilizes observed market betas[177] of publicly-traded companies that have approximately similar risk profiles as the State Project Company. Since the Project has no directly-comparable publicly-traded peers, Lazard evaluated various categories of publicly-traded companies that engage in activities similar to those of the Project (e.g., LNG companies, oil and gas producers, EPC companies and pipeline operators) to derive an illustrative implied cost of equity. The State Project Company's cost of debt will vary based on several factors (e.g., term, size, issuing entity, credit quality, structure, covenants, etc.); however, an illustrative range for the cost of debt can be derived from observing the cost of debt for various comparable historical borrowings across several different categories of debt (e.g., general obligation bonds, revenue bonds, tax-exempt bonds and project financings), as presented in the following sections.

[177] Beta is a measure of risk arising from exposure to general market movements. A beta below 1 typically indicates an asset with lower volatility than the market, and/or a volatile asset whose price movements are not highly correlated with the market. A beta above 1 generally means that the asset is both volatile and tends to move up and down with the market.

1. Cost of Equity

a. LNG Companies[178]

COMPARABLE COMPANIES	ENTERPRISE VALUE	NET DEBT	NET DEBT/ ENT. VALUE	NET DEBT/ EQUITY VALUE	LEVERED BETA[179]	UNLEVERED BETA[180]
Cheniere	$26,863	$10,680	39.76%	66.00%	1.621	0.996
		Median	**39.76%**	**66.00%**	**1.621**	**0.996**
		Mean	**39.76%**	**66.00%**	**1.621**	**0.996**

ASSUMPTIONS		SENSITIVITY RANGE LOW	SENSITIVITY RANGE HIGH	IMPLIED COST OF EQUITY LOW	IMPLIED COST OF EQUITY HIGH
Unlevered Beta[180]	0.996	0.996	0.996	11.95%	11.95%
Target Debt/Capitalization	35.00%	25.00%	45.00%	11.03%	13.21%
Levered Beta[181]	1.345				
Marginal Tax Rate	35.00%	35.00%	0.00%	11.95%	13.26%
Risk Free Rate of Return[182]	2.59%				
Equity Risk/Market Premium[183]	6.96%				
Cost of Equity[184]	**11.95%**				

Sources: Barra, Wall Street research, FactSet and Company filings.

178 Potential entities for further study and/or inclusion in this list include Sempra's LNG business, Dominion's LNG business and non-U.S. based LNG businesses, among others.
179 Betas as of December 31, 2014.
180 Unlevered Beta = Levered Beta/[1+(1-Tax Rate)(Debt/Equity)].
181 Levered Beta = (Unlevered Beta)[1+(1-Tax Rate)(Debt/Equity)].
182 Risk Free Rate is 30-Year Treasury Bond Yield as of January 8, 2015.
183 Represents the long-horizon expected equity risk premium based on differences of historical arithmetic mean returns on the S&P 500 from 1926 – 2013 (Ibbotson Associates' 2014 Yearbook).
184 Cost of Equity = (Risk Free Rate of Return) + (Levered Beta)(Equity Risk Premium).

b. Oil and Gas Producers

COMPARABLE COMPANIES	ENTERPRISE VALUE	NET DEBT	NET DEBT/ ENT. VALUE	NET DEBT/ EQUITY VALUE	LEVERED BETA[185]	UNLEVERED BETA[186]
BP	$134,098	$19,548	14.58%	17.44%	1.116	1.002
Chevron	221,778	11,219	5.06%	5.38%	1.106	1.069
Conoco	96,788	15,405	15.92%	19.27%	1.278	1.136
Exxon	417,273	16,820	4.03%	4.31%	0.961	0.935
Royal Dutch Shell	235,092	23,374	9.94%	18.27%	1.063	0.950
		Median	**9.94%**	**17.44%**	**1.106**	**1.002**
		Mean	**9.91%**	**12.93%**	**1.105**	**1.018**

ASSUMPTIONS		SENSITIVITY RANGE LOW	SENSITIVITY RANGE HIGH	IMPLIED COST OF EQUITY LOW	IMPLIED COST OF EQUITY HIGH
Unlevered Beta[186]	1.018	0.935	1.136	10.16%	11.78%
Target Debt/Capitalization	20.00%	10.00%	30.00%	10.19%	11.65%
Levered Beta[187]	1.184				
Marginal Tax Rate	35.00%	35.00%	0.00%	10.83%	11.45%
Risk Free Rate of Return[188]	2.59%				
Equity Risk/Market Premium[189]	6.96%				
Cost of Equity[190]	**10.83%**				

Sources: Barra, Wall Street research, FactSet and Company filings.

185 Betas as of December 31, 2014.
186 Unlevered Beta = Levered Beta/[1+(1-Tax Rate)(Debt/Equity)].
187 Levered Beta = (Unlevered Beta)[1+(1-Tax Rate)(Debt/Equity)].
188 Risk Free Rate is 30-Year Treasury Bond Yield as of January 8, 2015.
189 Represents the long-horizon expected equity risk premium based on differences of historical arithmetic mean returns on the S&P 500 from 1926 – 2013 (Ibbotson Associates' 2014 Yearbook).
190 Cost of Equity = (Risk Free Rate of Return) + (Levered Beta)(Equity Risk Premium).

c. EPC Companies

COMPARABLE COMPANIES	ENTERPRISE VALUE	NET DEBT	NET DEBT/ ENT. VALUE	NET DEBT/ EQUITY VALUE	LEVERED BETA[191]	UNLEVERED BETA[192]
Chicago Bridge & Iron	$6,687	$1,970	29.46%	43.73%	1.846	1.437
Fluor	8,123	(1,541)	(18.97%)	(16.50%)	1.462	1.638
KBR	1,437	(985)	(68.54%)	(40.51%)	1.653	2.244
Quanta	6,109	(59)	(0.97%)	(0.97%)	1.429	1.438
Technip	6,188	(943)	(15.24%)	(14.54%)	1.243	1.373
Willbros	465	192	41.37%	70.14%	1.973	1.355
		Median	**(8.11%)**	**(7.75%)**	**1.557**	**1.438**
		Mean	**(5.48%)**	**6.89%**	**1.601**	**1.581**

ASSUMPTIONS		SENSITIVITY RANGE		IMPLIED COST OF EQUITY	
		LOW	HIGH	LOW	HIGH
Unlevered Beta[192]	1.581	1.373	2.244	13.24%	20.00%
Target Debt/Capitalization	15.00%	5.00%	25.00%	13.97%	15.98%
Levered Beta[193]	1.762				
Marginal Tax Rate	35.00%	35.00%	0.00%	14.86%	15.54%
Risk Free Rate of Return[194]	2.59%				
Equity Risk/Market Premium[195]	6.96%				
Cost of Equity[196]	**14.86%**				

Sources: Barra, Wall Street research, FactSet and Company filings.

191 Betas as of December 31, 2014.
192 Unlevered Beta = Levered Beta/[1+(1-Tax Rate)(Debt/Equity)].
193 Levered Beta = (Unlevered Beta)[1+(1-Tax Rate)(Debt/Equity)].
194 Risk Free Rate is 30-Year Treasury Bond Yield as of January 8, 2015.
195 Represents the long-horizon expected equity risk premium based on differences of historical arithmetic mean returns on the S&P 500 from 1926 – 2013 (Ibbotson Associates' 2014 Yearbook).
196 Cost of Equity = (Risk Free Rate of Return) + (Levered Beta)(Equity Risk Premium).

d. Pipeline Operators

COMPARABLE COMPANIES	ENTERPRISE VALUE	NET DEBT	NET DEBT/ ENT. VALUE	NET DEBT/ EQUITY VALUE	LEVERED BETA[197]	UNLEVERED BETA[198]
Enbridge	$73,989	$33,790	45.67%	84.06%	1.169	0.756
ONEOK	19,613	10,190	51.96%	108.14%	1.321	0.776
Spectra	39,117	16,199	41.41%	70.68%	1.014	0.695
TransCanada	59,991	27,041	45.08%	82.07%	1.117	0.728
Williams	64,489	32,191	49.92%	99.67%	1.250	0.759
		Median	**45.67%**	**84.06%**	**1.169**	**0.756**
		Mean	**46.81%**	**88.92%**	**1.174**	**0.743**

ASSUMPTIONS		SENSITIVITY RANGE LOW	SENSITIVITY RANGE HIGH	IMPLIED COST OF EQUITY LOW	IMPLIED COST OF EQUITY HIGH
Unlevered Beta[198]	0.743	0.695	0.776	10.00%	10.86%
Target Debt/Capitalization	45.00%	35.00%	55.00%	9.57%	11.87%
Levered Beta[199]	1.138				
Marginal Tax Rate	35.00%	35.00%	0.00%	10.51%	11.99%
Risk Free Rate of Return[200]	2.59%				
Equity Risk/Market Premium[201]	6.96%				
Cost of Equity[202]	**10.51%**				

Sources: Barra, Wall Street research, FactSet and Company filings.

197 Betas as of December 31, 2014.
198 Unlevered Beta = Levered Beta/[1+(1-Tax Rate)(Debt/Equity)].
199 Levered Beta = (Unlevered Beta)[1+(1-Tax Rate)(Debt/Equity)].
200 Risk Free Rate is 30-Year Treasury Bond Yield as of January 8, 2015.
201 Represents the long-horizon expected equity risk premium based on differences of historical arithmetic mean returns on the S&P 500 from 1926 – 2013 (Ibbotson Associates' 2014 Yearbook).
202 Cost of Equity = (Risk Free Rate of Return) + (Levered Beta)(Equity Risk Premium).

2. Cost of Debt Precedents

a. Alaska Tax-exempt General Obligation Bonds

FINANCING DATE	ISSUER	TERM	YIELD	SIZE ($ IN MILLIONS)	MOODY'S RATING	GENERAL USE OF PROCEEDS
Aaa Rated						
01/23/2013	Alaska	12.5	1.950%	150	Aaa	Education
02/08/2012	Alaska	11.5	2.000%	176	Aaa	General Purpose
05/29/2008	Alaska Industrial Development & Export Authority	18.9	0.000%	107	Aaa	Industrial Development
04/15/2008	Alaska Municipal Bond Bank	30.0	5.200%	62	Aaa	General Purpose
05/18/2005	Alaska Housing Finance Corp	25.6	4.789%	164	Aaa	Multi Family Housing
Aa2 Rated						
02/20/2014	Alaska Municipal Bond Bank	25.0	4.250%	47	Aa2	General Purpose
11/14/2013	Alaska Municipal Bond Bank	34.7	4.600%	72	Aa2	General Purpose
03/12/2013	Alaska Municipal Bond Bank	33.9	3.460%	96	Aa2	General Purpose
05/24/2012	Alaska Municipal Bond Bank	19.3	3.500%	53	Aa2	General Purpose
09/15/2011	Alaska Municipal Bond Bank	25.0	4.300%	78	Aa2	General Purpose
04/14/2009	Alaska	20.3	4.680%	165	Aa2	Transportation

Sources: Bloomberg and EMMA

WEIGHTED AVERAGE YIELD (EXCLUDING ZERO YIELD ISSUANCES)	
Aaa Rated	3.174%
Aa2 Rated	4.220%

b. Alaska Tax-exempt Revenue Bonds

FINANCING DATE	ISSUER	TERM	YIELD	SIZE ($ IN MILLIONS)	MOODY'S RATING	GENERAL USE OF PROCEEDS
Aaa Rated						
11/22/2011	Alaska Housing Finance Corp	14.5	3.750%	71	Aaa	Single Family Housing
09/30/2010	Alaska Housing Finance Corp	30.2	4.625%	79	Aaa	Single Family Housing
10/03/2007	Alaska Housing Finance Corp	22.2	4.430%	96	Aaa	Transportation
08/29/2007	Alaska Railroad Corporation	13.9	5.000%	89	Aaa	Transportation
10/25/2006	Alaska Housing Finance Corp	33.6	4.660%	101	Aaa	Single Family Housing
08/22/2006	Alaska Railroad Corporation	15.0	4.320%	76	Aaa	Transportation
04/26/2006	Alaska	19.9	4.850%	68	Aaa	General Purpose
03/14/2006	Alaska	21.6	4.320%	176	Aaa	Airports
02/02/2006	CivicVentures	32.6	4.770%	111	Aaa	General Purpose
03/30/2005	Alaska Student Loan Corp	9.3	3.970%	88	Aaa	Student Loans
01/01/2005	Alaska Housing Finance Corp	36.9	4.540%	143	Aaa	Single Family Housing
10/28/2004	Alaska Industrial Development & Export Authority	29.4	0.000%	120	Aaa	Health Care
03/11/2004	Alaska Student Loan Corp	14.3	4.093%	75	Aaa	Student Loans
03/04/2004	Alaska Housing Finance Corp	28.8	4.750%	52	Aaa	Multi Family Housing
12/05/2002	Alaska Housing Finance Corp	21.6	0.000%	60	Aaa	Multi Family Housing
10/01/2002	Alaska Housing Finance Corp	37.7	4.950%	150	Aaa	Single Family Housing
09/05/2002	Alaska Housing Finance Corp	30.3	0.000%	79	Aaa	Multi Family Housing
04/01/2002	Alaska International Airport System	25.5	5.430%	128	Aaa	Airports
08/15/2001	Northern Tobacco Securitization Corp	27.8	5.620%	127	Aaa	General Purpose
08/02/2001	Alaska Housing Finance Corp	29.4	0.000%	77	Aaa	Single Family Housing
08/02/2001	Alaska Housing Finance Corp	29.4	0.000%	94	Aaa	Single Family Housing
02/01/2001	Alaska Housing Finance Corp	6.3	4.050%	75	Aaa	Single Family Housing
11/01/2000	Alaska Housing Finance Corp	40.1	6.00%	62	Aaa	Single Family Housing

FINANCING DATE	ISSUER	TERM	YIELD	SIZE ($ IN MILLIONS)	MOODY'S RATING	GENERAL USE OF PROCEEDS
06/01/2000	Alaska Housing Finance Corp	39.0	6.450%	56	Aaa	Single Family Housing
Aa1 Rated						
09/17/2014	Alaska	14.7	3.020%	31	Aa1	Health Care
Aa2 Rated						
11/17/2011	Alaska Industrial Development & Export Authority	29.9	4.830%	123	Aa2	Health Care
02/16/2011	Alaska Housing Finance Corp	16.8	5.020%	105	Aa2	General Purpose
08/26/2009	Alaska Housing Finance Corp	30.3	5.350%	81	Aa2	Single Family Housing
08/26/2009	Alaska Housing Finance Corp	31.3	0.000%	81	Aa2	Single Family Housing
05/28/2009	Alaska Housing Finance Corp	1.5	0.000%	81	Aa2	Single Family Housing
05/28/2009	Alaska Housing Finance Corp	1.5	0.000%	81	Aa2	Single Family Housing
09/30/2008	Alaska Housing Finance Corp	30.2	5.530%	81	Aa2	Single Family Housing
05/31/2007	Alaska Housing Finance Corp	34.5	0.000%	75	Aa2	Single Family Housing
05/31/2007	Alaska Housing Finance Corp	34.5	0.000%	75	Aa2	Single Family Housing
05/31/2007	Alaska Housing Finance Corp	34.5	0.000%	89	Aa2	Single Family Housing
11/30/2006	Alaska Industrial Development & Export Authority	29.9	4.380%	54	Aa2	Health Care
Aa3 Rated						
10/26/2000	Northern Tobacco Securitization Corp	30.6	6.600%	116	Aa3	General Purpose
A1 Rated						
02/24/2010	Alaska Industrial Development & Export Authority	17.1	4.500%	87	A1	Seaports/Marine Terminals

Sources: Bloomberg and EMMA.

WEIGHTED AVERAGE YIELD (EXCLUDING ZERO YIELD ISSUANCES)	
Aaa Rated	4.751%
Aa1 Rated	3.020%
Aa2 Rated	5.043%
Aa3 Rated	6.600%
A1 Rated	4.500%

c. Selected Precedent Taxable (Non-recourse) Project Financings

FINANCING DATE	PROJECT NAME	DEBT TERMS	PROJECT DESCRIPTION/NOTES
10/31/2014	Freeport LNG Export Project (Train 1[203])	**Tranche 1** Size: $2.6 billion Term Loan Pricing: L+200 **Tranche 2** Size: $1.2 billion Term Loan Pricing: L+200 **Tranche 3** Size: $100 million Term Loan	The Freeport, Texas-based Freeport LNG Project was originally launched in 2008 as an import terminal. In July 2014, it received FERC approval to construct and operate facilities in order to export LNG. Project financing for Train 1 was completed in Fall 2014.
08/06/2014	Cameron LNG Export Project	**Tranche 1** Size: $2.9 billion Term Loan Pricing: L+175 Term: 16 years Credit Rating: A/A3 **Tranche 2** Size: $2.5 billion Term Loan Pricing: L+125 Term: 16 years Credit Rating: A **Tranche 3** Size: $2.0 billion Term Loan Pricing: L+175 Term: 16 years Credit Rating: A **Tranche 4** Size: $350 million Standby Letter of Credit	Originally constructed as an import terminal, in 2011 Cameron LNG proposed adding export capabilities to its facilities in Hackleberry, Louisiana. In 2014, the project gained approval to export up to 12 MTPA of domestic LNG. The project is majority owned by Sempra, with GDF Suez, Sumimoto Mitsui Financial Group, Mitsubishi and Nippon Yusen K.K. the other owners.
05/28/2013	Sabine Pass Liquefaction	**Tranche 1** Size: $2.0 billion Senior Notes Pricing: 5.625% Term: 8 years **Tranche 2** Size: $1.0 billion Senior Notes Pricing: 6.250% Term: 9 years **Tranche 3** Size: $1.5 billion Senior Notes Pricing: 5.625% Term: 10 years **Tranche 4** Size: $2.0 billion Senior Notes Pricing: 5.750% Term: 10 years	Cheniere-owned Sabine Pass was originally constructed in 2008 as an import terminal, but has since altered its strategy, and intends to begin exporting LNG by 2016. Its Senior Notes issuances in 2013 and 2014 back the construction of Trains 1 – 4. To fully finance the remaining trains, additional debt or equity will likely be needed.
05/03/2010	Ruby Pipeline	**Tranche 1** Size: $25 million Revolver Pricing: L+300 Term: 7 years **Tranche 2** Size: $1.5 billion Term Loan Pricing: L+300 Term: 7 years	Ruby Pipeline, located in Colorado Springs, Colorado, owns and operates a 680-mile natural gas transmission pipeline system. It has a current capacity of approximately 1.5 Bcf/d, with expansion potential to 2.0 Bcf/d. In May 2010, Ruby Pipeline secured a $1.5 billion loan financing to support construction costs.

[203] An LNG train is an LNG plant's liquefaction and purification facility.

FINANCING DATE	PROJECT NAME	DEBT TERMS	PROJECT DESCRIPTION/NOTES
02/07/2008	LNG Clean Energy	**Tranche 1** Size: $870 million Term Loan Pricing: L+150 Term: 14 years	LNG Clean Energy's 2008 debt issuance backed the $1.1 billion construction of LNG Clean Energy, an import terminal on the Port of Pascagoula in Mississippi.
12/16/2004	Qatargas 2	**Tranche 1** Size: $1.1 billion Term Loan Term: 25 years **Tranche 2** Size: $530 million Islamic Financing Term: 156 years **Tranche 3** Size: $800 million Export Credit Facility **Tranche 4** Size: $5.2 billion Term Loan	Exxon and Qatar Petroleum-owned Qatargas 2's 2004 $7.6 billion project financing was the largest energy project financing in the world at the time. The project involves construction of two trains, the acquisition of several LNG carriers and construction of a receiving terminal in the U.K.

Sources: Bloomberg, FERC, LoanConnector and S&P Leveraged Commentary and Data.

d. Selected Precedent Taxable (Recourse) Financings

FINANCING DATE	ISSUER	DEBT TERMS	MOODY'S RATING
04/30/13	Sterling Resources	**Tranche 1:** Size: $300 million Pricing: 9.000% Revenue Bonds Term: 7.0 Years	NR
04/23/13	Transportadora de Gas del Peru	**Tranche 1:** Size: $850 million Pricing: 4.250% Senior Unsecured Notes Term: 15.0 Years	Baa2
03/19/13	IGas Energy	**Tranche 1:** Size: $165 million Pricing: 10.000% Senior Secured Notes Term: 5.0 Years	NR
02/04/13	Geopark Chile	**Tranche 1:** Size: $300 million Pricing: 7.500% Guaranteed Bonds Term: 7.0 Years	NR
11/17/09	State of Qatar	**Tranche 1:** Size: $7.0 billion Senior Notes Pricing: 5.250% Term: 10.2 Years **Tranche 2:** Size: $7.0 billion Senior Notes Pricing: 6.400% Term: 30.2 Years **Tranche 3:** Size: $5.2 billion Senior Notes Pricing: 4.000% Term: 5.2 Years	Aa2
07/23/09	Dolphin Energy	**Tranche 1:** Size: $1.3 billion Pricing: 5.888% Senior Secured Notes Term: 9.9 Years	Aa3
07/22/09	Georgia Municipal Gas Authority	**Tranche 1:** Size: $100 million Pricing: Revenue Bonds, coupon range 2.571% – 4.037% Term: 4.1 Years	A1

FINANCING DATE	ISSUER	DEBT TERMS	MOODY'S RATING
07/16/09	Ras Laffan Liquefied Natural Gas Co.	**Tranche 1:** Size: $2.3 billion Guaranteed Senior Secured Notes Pricing: 6.750% Term: 10.2 Years **Tranche 2:** Size: $2.3 billion Guaranteed Senior Secured Notes Pricing: 5.500% Term: 5.2 Years **Tranche 3:** Size: $2.3 billion Guaranteed Senior Secured Notes Pricing: 4.500% Term: 3.2 Years	Aa2
06/02/09	City of San Antonio	**Tranche 1:** Size: $375 million Pricing: 5.985% Revenue Bonds Term: 29.7 Years	Aa1
05/11/09	Maritimes & NE Pipeline	**Tranche 1:** Size: $500 million Pricing: 7.500% Global Bonds Term: 5.0 Years	Baa3

Sources: LoanConnector and S&P Leveraged Commentary and Data.

B. Precedent LNG Export Projects

The following are examples of LNG export projects that either have been completed or are in the late stages of development. These examples are included to provide background on the financing and structuring decisions of projects similar to the AKLNG Project.

1. Sabine Pass Liquefaction LNG Project

a. Overview of Project

The Sabine Pass LNG Liquefaction Project ("Sabine Pass" or "Sabine Pass Liquefaction"), located in Cameron Parish, Louisiana, is the first LNG export facility in the Lower 48. The terminal was originally constructed by Cheniere Energy Partners, L.P. ("Cheniere") in 2008 as an LNG import facility with unloading and regasification capabilities. However, due to a sharp increase in domestic shale gas production, the U.S.'s need for imported LNG has drastically reduced since 2008. This shift in need initially called into question the potential for profitability at Sabine Pass.[204]

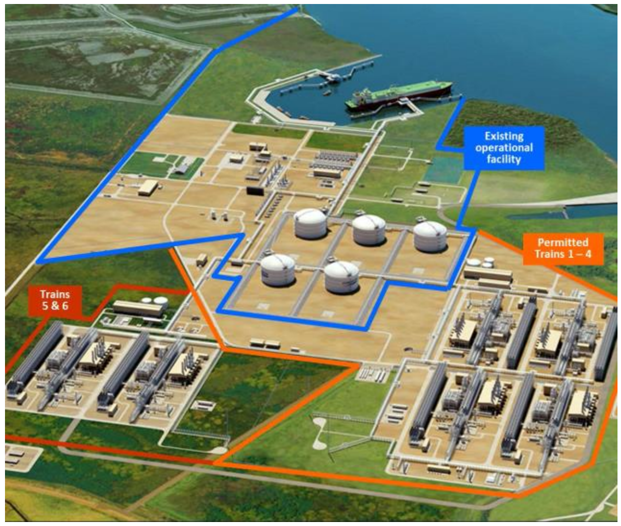
Cheniere has since pivoted its Sabine Pass strategy and is currently developing liquefaction capabilities and export terminals at the site with a targeted in-service date ("ISD") of early 2016. The Sabine Pass location is well-positioned to provide LNG export services due to its proximity to shale gas in Louisiana and Texas, its access to the Gulf Coast and its existing interconnections with multiple pipelines. As a result of this conversion, Sabine Pass is expected to be the first joint import/export terminal in the world. The liquefaction expansion project is expected to cost $12 billion for the first four trains and to have a capacity of ~18 MTPA.[205]

Sabine Pass has currently contracted out its output to a variety of offtakers, including Japanese firms such as Chubu Electric and Kansai Electric Power, as well as European firms such as Total and Centrica.

Cheniere is a publicly-traded LNG project developer and operator based in Houston; the firm has a market capitalization of approximately $17 billion.[206]

204 "Shale Gas: Terminal Decline No Longer," Financial Times, April 23, 2012.
205 "Sabine Pass LNG Expansion Benefits Highlighted," LNG Industry, September 19, 2014.
206 FactSet.

b. Map of Assets



Source: Cheniere.

c. Overview of Financing

Cheniere is targeting a 65/35 debt-to-equity ratio to finance Sabine Pass.[207]

Equity in Sabine Pass has been contributed by Cheniere and Blackstone. Cheniere financed a $500 million equity stake in the project through sales of equity at the parent company level to two Asian investment firms in early 2012.[208] A Blackstone-led consortium of private investors raised the remaining $1.5 billion of equity in mid-2012. Blackstone's equity investment is structured using a special type of "payment in kind" accreting equity that is convertible into common equity in Cheniere's Sabine Pass subsidiary. This structure allowed Blackstone to gain several seats on the subsidiary's board.[209]

Cheniere has also secured ~$6.5 billion in debt financing. The senior note financing that Cheniere utilized has covenants on issuing additional debt or preferred stock, distributing capital, and selling or transferring assets, and is secured concerning a *pari passu* basis by all of Sabine Pass Liquefaction's assets. Sabine Pass Liquefaction may make distributions only after certain conditions have been satisfied, including the substantial completion of the first two LNG trains and the achievement of a projected debt service coverage ratio of 1.25x. The senior notes also carry a "make-whole" provision that allows the company to redeem the senior notes at a "make-whole" price[210] plus any accrued or unpaid interest.[211]

207 "Non-recourse construction/term loan - Cheniere Energy Partners," Société Générale, October 8, 2012.
208 "Temasek, RRJ Capital to Invest in Cheniere Energy," Wall Street Journal, May 7, 2012.
209 Cheniere Energy Partners, LP company filings.
210 A borrower often can repay certain types of debt early at a premium called the "make-whole" price.
211 Cheniere company filings.

Sabine Pass secured a $5.9 billion credit facility in 2013 and a $325 million letter of credit reimbursement agreement, but as of September 2014, the company was not borrowing any money from either facility. The credit facility was priced on a floating basis at a 2.3% – 3.0% spread to LIBOR prior to completion of the fourth liquefaction train and priced at 2.3% – 3.5% spread thereafter. The credit facility was structured such that, as Cheniere issues additional senior notes, the size of the credit facility commitment available will decrease. As of September 30, 2014, $2.7 billion of the credit facility was available.[212]

SABINE PASS LIQUEFACTION CAPITALIZATION TABLE ($ IN BILLIONS)[213]

SECURITY	AMOUNT	PRICING	TERM
Equity			
Cheniere Equity	$0.5	NA	NA
Blackstone-led Consortium Equity	1.5	NA	NA
Total Equity	**$2.0**		
Debt			
2021 Senior Notes (Project Finance)	$2.0	5.625%	8 years
2022 Senior Notes (Project Finance)	1.0	6.250%	9 years
2023 Senior Notes (Project Finance)	1.5	5.625%	10 years
2024 Senior Notes (Project Finance)	2.0	5.750%	10 years
Total Debt	**$6.5**		

Source: Company filings, LoanConnector and news releases.

212 Cheniere Energy Partners, LP company filings.

213 The table displays all debt outstanding and equity invested in Sabine Pass Liquefaction. To fully finance the entire project (e.g., Trains 1 – 6), Cheniere will likely need to issue incremental debt or equity.

2. Gorgon LNG Project

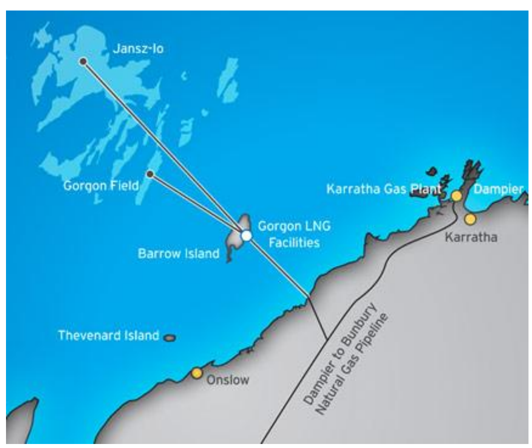
a. Overview of Project

The Gorgon LNG Project ("Gorgon LNG"), located on Barrow Island off the Western Coast of Australia, is a large integrated LNG project that includes upstream development of remote gas fields, an LNG facility and a 44-mile gas pipeline. The project is situated on Australia's largest gas resource, which could hold more than 40 Tcf of natural gas, and is expected to have a capacity of 16 MTPA.[214] The main sponsors of Gorgon LNG include Chevron (47% ownership), Exxon (25% ownership) and Royal Dutch Shell (25% ownership). Several Japanese utilities (combined 3% ownership) compose the remainder of the ownership structure.[215]

Although originally estimated to cost $37 billion in 2009, the project is now expected to cost $54 billion, including gas field development costs. These cost overruns include higher work-related costs, weather and productivity issues, and, most significantly, the strengthening of the Australian dollar.[216] As a result of these cost overruns, the project is the largest single energy investment in Australia's history.[217]

The sponsors have executed long-term sale and purchase agreements ("SPAs") with several Japanese, South Korean, Indian and Chinese companies for approximately 65% of the project's output. As of November 2014, the project is 87% complete and has a targeted ISD of late 2015.[218]

b. Map of Assets



Source: Chevron.

214 Chevron company filings.
215 "AUSTRALIA," E, August 28, 2014.
216 "Take-off for Australian LNG," LNG 18, February 18, 2014.
217 "Chevron's Gorgon project 78% complete," The Australian Business Review, March 2014.
218 Chevron Press Release, October 31, 2014.

c. Overview of Financing

The Gorgon LNG Project relies upon Chevron, Exxon, Royal Dutch Shell and, to a lesser extent, Osaka Gas, Tokyo Gas and Chubu Electric Power to fund the project using their respective balance sheets. This is in contrast to the financing profile of many other LNG projects, which typically utilize non-recourse project financing.

The three Japanese utility project sponsors invested in Gorgon LNG's equity (specifically into Chevron's stake) in conjunction with their negotiations to purchase gas from Gorgon via 25-year SPAs. These sponsors have utilized loans from state-owned lending institutions to fund their respective stakes in the project.

Additionally, as a result of the cost overruns described above, the sponsors of the project have had to contribute additional funds to project development.

GORGON CAPITALIZATION TABLE[219]

SECURITY	OWNERSHIP	PRICING	TERM
Equity			
Chevron	47.3%	NA	NA
Exxon	25.0%	NA	NA
Royal Dutch Shell	25.0%	NA	NA
Osaka Gas	1.3%	NA	NA
Tokyo Gas	1.0%	NA	NA
Chubu Electric Power	0.4%	NA	NA
Total Equity	**100.0%**	**NA**	**NA**

Source: Company filings, LoanConnector and news releases.

219 Ownership amounts only refer to respective shares of costs and gas produced—individual parties can finance their respective capital requirements in accordance with individual capital budgeting targets.

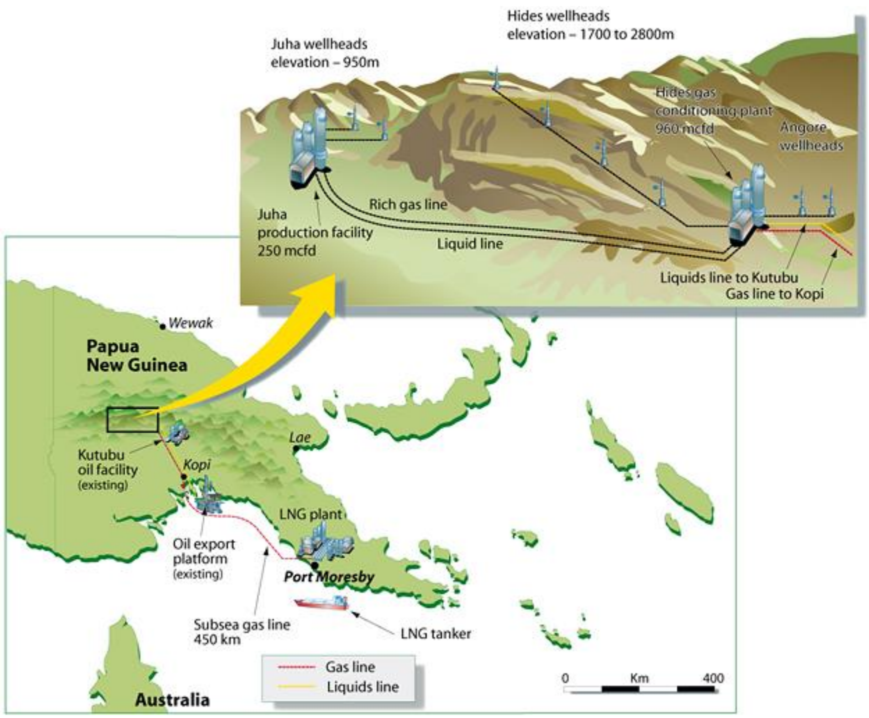
3. Papua New Guinea

a. Overview of Project

The PNG LNG Project, located in Papua New Guinea, is an integrated LNG development that includes upstream production at gas fields, a 435-mile above- and below-sea pipeline, a liquefaction terminal and export facility. The main sponsor of the project is Exxon, with support and investment provided by the Government of Papua New Guinea, Oil Search, Santos and other natural resource extraction companies.[220]

The project has a capacity of 7 MTPA and is expected to produce 9 Tcf of gas over its lifetime. The sponsors have contracted out the supply to a variety of buyers in Japan, China and Taiwan. The project is estimated to have cost $19 billion and produced its first gas in May 2014.[221]

b. Map of Assets



Source: Esso Highlands.

[220] "PNG LNG: A World Class Financing Venture," ExxonMobil Gas & Power Marketing Company, April 2013 ("Exxon PNG Report").
[221] Exxon PNG Report.

c. Overview of Financing

The firms that provided equity to the project included Exxon (33% of equity), Oil Search (29% of equity), Santos (13% of equity), and Japan Papua New Guinea Petroleum and Nippon Oil Exploration (combined 5% of equity). Three Papua New Guinea-owned national firms also contributed a combined 20% of the equity.[222]

The PNG LNG Project utilized significant financing from public export credit agencies. Six export credit agencies, including the Export-Import Bank of the United States and the JBIC, have provided $8.3 billion of loans to Exxon and the PNG LNG Project. In addition to investing equity and being the main operator of the project, Exxon also provided a $3.8 billion loan from a subsidiary. To round out the financing, 17 commercial banks provided a total of $3.5 billion.[223,224]

PNG LNG CAPITALIZATION TABLE ($ IN BILLIONS)[225]

SECURITY	AMOUNT	PRICING	TERM
Equity			
Exxon	$1.2	NA	NA
Oil Search	1.0	NA	NA
National Petroleum Company of PNG	0.6	NA	NA
Santos	0.5	NA	NA
Nippon Oil	0.2	NA	NA
MRDC	0.1	NA	NA
Total Equity	**$3.5**		
Debt			
2024 Term Loan (Project Finance)	$3.5	L+325	15 years
2026 JBIC Export Credit (Project Finance)	1.8	NA	17 years
2026 Export-Import Bank of the United States Export Credit (Project Finance)	2.2	NA	17 years
2026 Export-Import Bank of China Export Credit (Project Finance)	1.3	NA	17 years
2026 Export Finance & Insurance Corp. (Project Finance)	0.4	NA	17 years
2026 Export Credit (Project Finance)	0.8	L+150	17 years
2026 Export Credit (Project Finance)	0.9	L+165	17 years
2026 Export Credit (Project Finance)	1.0	L+175	17 years
2026 Exxon Loan (Project Finance)	3.8	NA	17 years
Total Debt	**$15.5**		

Source: Company filings, LoanConnector and news releases.

222 Exxon PNG Report.
223 Exxon PNG Report.
224 "Exxon Secures $1.5B For $19B Papua New Guinea LNG Project," Law360, October 4, 2013.
225 Equity investments assume necessary equity contributions given current debt levels and projected cost of the PNG LNG Project. Also assumes that equity is invested in levels commensurate to project ownership.

4. Qatargas 2 LNG Project

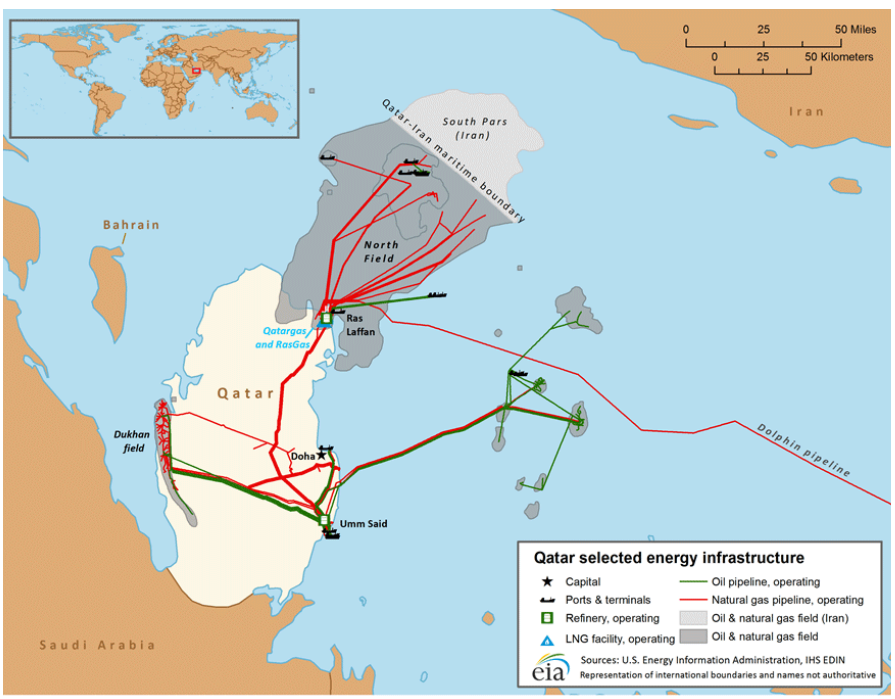
a. Overview of Project

The Qatargas 2 LNG Project, located in Qatar, is the world's first fully-integrated LNG development. The project included the development of 30 wellheads, several unmanned platforms, liquefaction and export facilities in Qatar, several tankers and an LNG receiving facility in Europe. The main sponsors of the project are Qatar Petroleum, a company owned by the government of Qatar, ExxonMobil and Total. The project cost was over $12 billion and has a capacity of ~16 MTPA.[226, 227]

Although the original goal of the project was to supply the U.K. with LNG, in the wake of the 2011 Fukushima crisis, much of the LNG is now projected to be shipped to Japan and other Asian countries. The sponsors negotiated SPAs for over 50% of production with the U.K.

The project is notable in that it was the first LNG project in which the entire value chain, from wellhead to terminal, was developed and financed by the same partners. Additionally, the project involved the development of the two largest liquefaction trains in the world.[228]

b. Map of Assets



Source: EIA.

226 "Milestones : Qatar Gas Project Pushes Bounds Of Project Finance," Global Finance, February 1, 2005.
227 Qatargas press release.
228 "White & Case Closes Largest Ever Energy Financing," White & Case, December 16, 2004 ("White & Case Report").

c. Overview of Financing

The sponsors targeted a 70/30 debt-to-equity ratio when financing the project.[229]

Qatar Petroleum owns the majority equity stake in both trains of the LNG plant (70% of train 1 and 65% of train 2), while the private sponsors, Exxon and Total, own the balance.[230]

The Qatargas 2 LNG Project also utilized significant debt financing. Altogether, $7.6 billion was provided for the project, which, at the time, made it the single largest energy project financing in history. In total, 57 institutions provided debt financing for the project, including 36 commercial banks, an export credit agency, six Islamic banks and an Exxon lender on the upstream side, and 12 commercial banks and an Exxon lender on the receiving terminal side. Notably, the project utilized the largest amount of long-term Islamic project financing ($530 million) in history.[231]

QATARGAS 2 CAPITALIZATION TABLE ($ IN BILLIONS)[232]

SECURITY	AMOUNT	PRICING	TERM
Equity			
Qatar Petroleum	$3.0	NA	NA
Exxon	1.1	NA	NA
Total	0.4	NA	NA
Total Equity	**$4.4**		
Debt			
2029 South Hook Term Loan (Project Finance)	$1.1	NA	25 Years
2020 Islamic Financing (Project Finance)	0.5	NA	15 Years
2022 Export Credit (Project Finance)	0.8	NA	NA
2020 Term Loan	5.2	NA	NA
Total Debt	**$7.6**		

Source: Company filings, LoanConnector and news releases.

229 "Issues Facing U.S. Shale Gas Exports To Japan," Pipeline & Gas Journal, December 2011.
230 Qatargas press release.
231 White & Case Report.
232 Equity investments assume necessary equity contributions given current debt levels and projected cost of the Qatargas 2 Project. Also assumes that equity is invested in levels commensurate to project ownership.

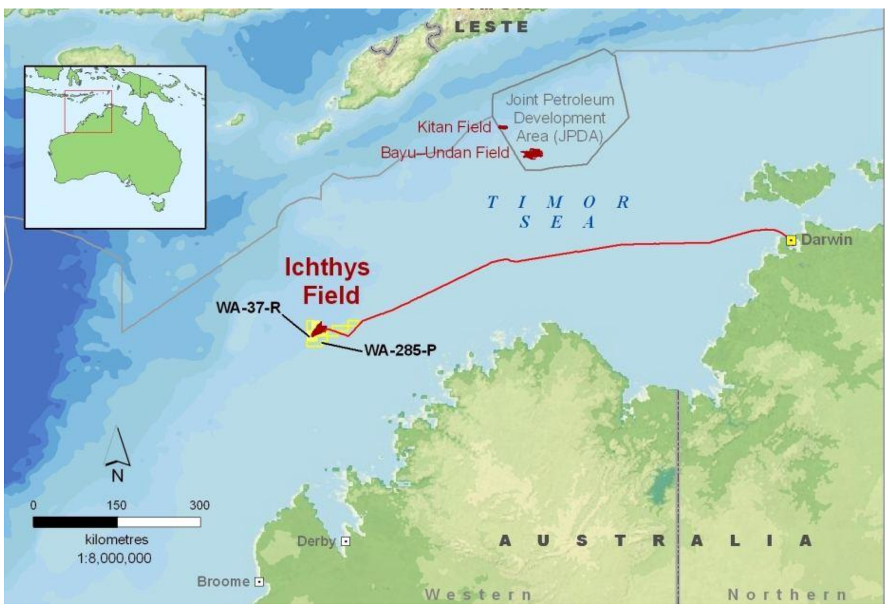
5. Ichthys LNG Project

a. Overview of Project

The Ichthys LNG Project, located off the coast of Western Australia, is an integrated LNG development. The project includes the development of a central processing facility, a floating production, storage and offtake vessel, a 556-mile pipeline and liquefaction facilities. The main sponsors of the project are INPEX (a Japanese oil company with a market capitalization of $17 billion), Total, Tokyo Gas, Osaka Gas, Chubu Electric Power and Toho Gas. The project is expected to cost over $34 billion and has a capacity of approximately 8.4 MTPA. The project has a targeted ISD of late 2016.[233]

The project is also the first in which a Japanese company has led a multinational LNG project as an operator.[234]

b. Map of Assets



Source: INPEX.

[233] "Ichthys LNG Project," INPEX, 2014.
[234] "INPEX Secures $20 Bln in Loans for Ichthys LNG Project (Australia)," Offshore Energy Today, December 18, 2012.

c. Overview of Financing

The Ichthys LNG Project secured arrangements for $20 billion of project financing, the largest amount ever arranged in international markets. The sponsors collected the funds from a variety of sources, including eight export credit agencies and 24 commercial banks.[235]

The project's equity owners are also providing debt financing. INPEX (66% of equity), Total (30% of equity) and the Japanese utilities (combined 4% of equity) are contributing $4 billion in loans, in proportion to each company's equity stake.[236]

During the construction phase of the project, each of the sponsors will severally guarantee the repayment of the loans. Japan Oil, Gas and Metals National Corporation, a Japanese government owned agency, has agreed to guarantee $2 billion of INPEX's commitment.[237]

ICHTHYS CAPITALIZATION TABLE ($ IN BILLIONS)[238]

SECURITY	AMOUNT	PRICING	TERM
Equity			
INPEX	$9.2	NA	NA
Total Equity	4.2	NA	NA
Tokyo Gas	0.2	NA	NA
Osaka Gas	0.2	NA	NA
Chubu Electric Power	0.1	NA	NA
Toho Gas	0.1	NA	NA
Total Equity	**$14.0**		
Debt			
Export Credit Agency Direct Loans (Project Finance)	$5.8	NA	NA
ECA insured/Guaranteed Commercial Loans	5.4	NA	NA
Commercial Loans	4.8	NA	NA
Sponsor Loans	4.0	NA	NA
Total Debt	**$20.0**		

Source: Company filings, LoanConnector and news releases.

The project also uses novel structuring approaches to share development risk among the equity owners. The project's downstream facilities are owned by a special purpose vehicle that is the main borrower under the project financing. The upstream facilities are part of an unincorporated joint venture. Each sponsor owns an equal interest in both the upstream and downstream entities.

235 "Ichthys LNG Project Completes Project Financing Arrangements," INPEX, December 18, 2012 ("INPEX Report").
236 INPEX Report.
237 INPEX Report.
238 Equity investments assume necessary equity contributions given current debt levels and projected cost of the Ichthys LNG Project. Also assumes that equity is invested in levels commensurate to project ownership.

C. List of Selected Key Terms

Below is a list of key terms and definitions used throughout this Report. Where a term is defined or otherwise explained in further detail in this Report, the relevant section is indicated in parentheses.

- **AAPP:** Arctic Alaska Petroleum Province; location of the majority of Alaska's petroleum reserves (Section III.B.1.a)
- **AFUDC:** Allowance for Funds Used During Construction; a return-on-capital calculation for construction financing (Section IV.F)
- **AGDC:** Alaska Gasline Development Corporation (Section III.C and Section IV.C)
- **AGIA:** Alaska Gasline Inducement Act; 2007 State statute providing, among other things, for reimbursement of natural gas developers' expenses to promote development of a natural gas pipeline (Section III.D)
- **ANGDA:** Alaska Natural Gas Development Authority (Section III.C)
- **ANGTA:** Alaska Natural Gas Transportation Act; 1976 Federal statute promoting expedited development of a pipeline to deliver natural gas from Alaska to the Lower 48 (Section III.C)
- **ANWR:** Arctic National Wildlife Refuge; Federal area within Alaska's North Slope with significant undiscovered oil (Section III.B.1.a)
- **ARMB:** Alaska Retirement Management Board; entity controlling seven State retirement systems (Section VI and Section VI.B)
- **ASAP:** Alaska Stand Alone Pipeline; proposed 727-mile pipeline southward from the North Slope to an existing pipeline system in the Matanuska-Susitna Borough (Section III.C)
- **BBL:** Billion barrels (unit of *oil* volume)
- **Bcf:** Billion cubic feet (unit of *natural gas* volume)
- **CAPM:** Capital asset pricing model; framework for calculating cost of equity (Section VII)
- **CBRF:** Constitutional Budget Reserve Fund (Section V.A.1 and Section V.B.2)
- **Cook Inlet:** Area in Southcentral Alaska, location of substantial oil and gas reserves (Section III.B.2.b.ii)
- **DOE:** U.S. Department of Energy
- **EIA:** U.S. Energy Information Administration
- **EPC:** Engineering, Procurement and Construction; final phase of Project before operations, encompasses final engineering and preparation, and expected to cost approximately $52.8 billion (midpoint) (Section IV.D and Section IV.G.1)
- **FEED:** Front-End Engineering and Design; final phase of Project before major construction, encompasses contract preparation and financing arrangements, and expected to cost approximately $1.8 billion (midpoint) (Section IV.D and Section IV.G.1)
- **FERC:** Federal Energy Regulatory Commission
- **FID:** Final Investment Decision; last Project milestone before EPC phase (Section IV.D and Section IV.F – IV.G.1)

- **FTSA:** Firm Transportation and Services Agreement; agreement describing the tariff that the State of Alaska pays TransCanada under the Memorandum of Understanding (Section IV.C and IV.F)
- **Fuel Use Act:** Powerplant and Industrial Fuel Use Act; 1978 Federal statute restricting construction of new power plants and boilers (Section III.C – III.D)
- **FY:** the State of Alaska's Fiscal Year starts on July 1 and ends on June 30 (e.g., Fiscal Year 2014 ended on June 30, 2014)
- **GeFONSI:** General Fund and Other Non-segregated Investments; includes the State's general operating fund (Section V.B.2)
- **GTP:** the Project's gas treatment plant (Section IV.B)
- **GW:** Gigawatt (unit of power equivalent to one billion watts)
- **Heads of Agreement:** agreement that establishes non-binding guiding principles and partner roles for the Project as well as important commercial and operating arrangements among each of the key Project parties (Section IV.A and Section IV.C)
- **IPO:** Initial public offering; method of issuing shares to public investors (Section VII.B.1)
- **ISD:** In-service date; date upon which a project becomes available for operations
- **JBIC:** Japan Bank for International Cooperation (Section VI.B)
- **KOGAS:** Korea Gas Corporation; state-owned South Korean utility (Section III.A.2)
- **LIBOR or L:** London Interbank Offered Rate; benchmark rate that banks charge each other for short-term loans (Section VII and Section XI.A.2)
- **LNG:** Liquefied natural gas
- **LNG Plant:** the Project's liquefaction facility (Section IV.B)
- **Lower 48:** Contiguous U.S. states, consisting of 48 states and Washington, D.C.
- **Mcf:** Thousand cubic feet (unit of *natural gas* volume)
- **MMBD:** Millions of barrels per day (unit of *oil* volume)
- **MMBtu:** Million British thermal units (unit of energy)
- **MOU:** Memorandum of Understanding; agreement between the State and TransCanada (Section IV.F)
- **MTPA:** Metric tons per annum (unit of *LNG* volume)
- **North Slope:** Region in northern Alaska bound by the Brooks Range and Arctic Ocean (Section III.B.1 – III.B.2)
- **NPRA:** National Petroleum Reserve-Alaska; area within Alaska's North Slope with significant undiscovered oil (Section III.B.1.a)
- **NPV:** Net present value; the present value of a series of future cash flows (Section IV.G.5)
- **OMB:** State of Alaska Office of Management and Budget; prepares and manages the State's budget on behalf of the Governor (Section V.A.1)

- **PCE Endowment Fund:** Power Cost Equalization Endowment Fund; State fund created to provide affordable electricity for rural Alaska regions (Section V.B.2)
- **Pipeline:** the Project's natural gas pipeline (Section IV.B)
- **Point Thomson:** Area located in Alaska's North Slope; location of an existing oil and gas field (Section IV.B)
- **Pre-FEED:** Pre-Front End Engineering and Design; initial phase of Project, encompasses preliminary engineering and planning, and expected to cost approximately $400 million (midpoint) (Section IV.D and Section IV.G.1)
- **Project:** the Alaska LNG Project
- **Prudhoe Bay:** Area located in Alaska's North Slope; location of an existing oil and gas field (Section III.B.2.b.i)
- **SB 138:** Senate Bill 138; 2014 State statute facilitating Alaska individuals' and entities' participation in ownership of a North Slope natural gas pipeline (Section I)
- **SBRF:** Statutory Budget Reserve Fund (Section V.A.1 and Section V.B.2)
- **SPA:** Sale and Purchase Agreement
- **Stranded Gas Act:** Alaska Stranded Gas Development Act; 1998 State statute enabling State negotiation of terms for oil producers dealing with stranded gas (Section III.C)
- **TAPS:** Trans-Alaska Pipeline System; 800-mile pipeline constructed in the 1970s to allow for the transportation of natural gas from Prudhoe Bay to Valdez (Section III.B.2.b.i)
- **Train:** Refers to an LNG plant's liquefaction and purification facility (Section XI.B)
- **Tcf:** Trillion cubic feet (unit of *natural gas* volume)
- **USGS:** U.S. Geological Survey; scientific agency of the U.S. Government
- **WACC:** Weighted average cost of capital; blended cost of financing that takes into consideration the amount of debt and equity in an entity's capital structure, and the respective costs (Section VII)
- **WTI:** West Texas Intermediate; a type of crude oil, the price of which is often used as a benchmark for oil prices (Section III.A.1)