ALASKA NORTH SLOPE ROYALTY STUDY
STUDY HIGHLIGHTS

PREPARED FOR THE STATE OF ALASKA
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The Alaska Liquefied Natural Gas (AKLNG) project is a proposed project to liquefy Alaska North Slope (ANS) gas and export it as LNG, primarily to Asian markets.

The project is comprised of three main components:
- Gas treatment plant (GTP),
- Pipeline,
- Liquefied natural gas (LNG) plant.

The total estimated capital cost of the project is $45 billion falling within a range of $39-$54 billion.

Natural gas to supply the project is anticipated to come from the proven reserves at the Prudhoe Bay and Point Thomson units on the Alaska North Slope.

The key project sponsors are Exxon Mobil, ConocoPhillips and BP (referred to in this study as Producers) with potential participation by TransCanada and the State of Alaska.

Target final investment decision for the project is projected around 2017-18 with a commercial operation date around 2023-24.
The AKLNG Project has recently seen momentum with the 3 Producers along with TransCanada coming together to evaluate and advance the AKLNG Project.

The AKLNG Project has the potential to provide hundreds of billions of dollars in value to the State of Alaska as well as the project’s investors; the benefits to Alaskans include new revenues, affordable energy supplies, new jobs and economic activity.

The State of Alaska, Department of Natural Resources (DNR) commissioned a study to document and understand four major commercial elements that could influence the various stakeholders’ returns from the AKLNG Project:

- LNG markets
- Supply chain elements
- Fiscal framework – International and Alaska
- Risk allocation/commercial structure
The purpose of this study is to provide information that can help the State to protect its royalty interest in the state’s gas and ensure that the State maximizes the value of its natural gas.

The study examined how the State’s fiscal terms with a particular focus on royalty terms can affect the success of the AKLNG project in its role as the principal land owner of the oil and gas resources of the North Slope.

The Study was undertaken by a team that included Black & Veatch and Daniel Johnston, Inc. under the leadership of DNR along with support and consultation by Department of Revenue (DOR). Additionally, inputs and assumptions of AKLNG Project sponsors were considered.
EXECUTIVE SUMMARY – BACKGROUND & SCOPE

- Assessment of a project of the scope of AKLNG requires examination of numerous complex variables that cannot be determined with a high degree of certainty.
- In most cases, a conservative approach was taken when applying forecasts and assumptions.
- Many reasonable scenarios can be derived where the AKLNG project is economic, and vice versa.
- It should be recognized that market and project related variables, that remain as yet unresolved, can modify the economics as presented here.
- The findings in this study represent Black & Veatch’s view based on the information available to date and do not necessarily represent the views of the State of Alaska.
EXECUTIVE SUMMARY – KEY FINDINGS

LNG Markets

- The LNG market is characterized by highly capital intensive projects underpinned by long-term contractual relationships across the supply chain.

- The LNG market is in an illiquid, opaque market consisting of very few participants and is structured on the basis of long-term, 20+ year contracts as opposed to the global oil market which is highly liquid, extremely transparent, comprised of many participants and is structured on the basis of short term trade.

- Global LNG demand is projected to grow by 50% between 2013 and 2020 and to double by 2030. However potential sources of supply are expanding as well thereby creating significant competition for capturing this growing market.

- AKLNG project could be economically feasible with changes to the project’s cost structure and the state’s fiscal framework.

- AKLNG will have to compete successfully for buyers in order to meet its targeted 2024 in-service date.

Note: Includes AKLNG, other new projects, and projects under development. Source: Team Analysis, various demand studies.
EXECUTIVE SUMMARY – KEY FINDINGS

Supply Chain Elements

- In line with the rising costs of LNG projects world-wide, AKLNG project cost estimates have risen by 67% since an equivalent project was evaluated in 2008 to a current estimate of $45 Billion for the GTP, Pipeline and LNG liquefaction and marine facilities. Equivalent estimates from AKLNG project sponsors are in the range of $39 - $54 Billion.

- Large, complex LNG projects typically have an integrated commercial structure from production through liquefaction to give project sponsors maximum control across the supply chain.

- The AKLNG project is expected to have an integrated structure.

- Ensuring transparency along the supply chain, open access for third parties and alignment of interests between the State and Producers become challenging with a Producer-owned integrated project.
EXECUTIVE SUMMARY – KEY FINDINGS

Fiscal Framework

- AKLNG is competing for capital with Producers’ projects worldwide and for market share with other sources of supply.

- Similar to other oil and gas projects, LNG projects have either concessionary or contractual fiscal systems with total government take ranging from 45% - 80% for comparable LNG projects reviewed that have achieved commercial operation.

- Government take in Alaska in the 70% - 85% range is high for a complex LNG project, although overlapping with the range of government take for the other LNG projects reviewed. Expected IRR for the Producers of approximately 15% for the upstream and midstream components of the project may be insufficient for the Producers to move forward, given their investment alternatives and AKLNG project uncertainties.

- Changes to the project’s cost structure and the State’s fiscal framework can make the AKLNG Project more economic and competitive.
EXECUTIVE SUMMARY – KEY FINDINGS

Fiscal Framework

• Incentives including modifications in royalty and/or production tax are among the alternatives available to the State to help improve the relative competitiveness of the project under various scenarios.

• There are various risks to the State from significantly reducing or eliminating its royalty share;
  — Royalties represent Alaska’s ownership stake and reducing royalties has implications for the Alaska Permanent Fund
  — Royalty reduction would not protect the State from risks posed by misalignment between the State and Producers interests wherein Producers are able to shift revenues between upstream and midstream components of the project to the detriment of the State
EXECUTIVE SUMMARY – KEY FINDINGS

Fiscal Framework

• In reviewing alternatives for royalty, an election by the State to take its royalty in-kind (RIK) could result in a substantial increase in the State’s risk exposure and potential loss of royalty value.
  — An election by the State to take its royalty in-kind could necessitate the need for the State to enter into a large number of complex commercial agreements. The State would be disadvantaged in the creation of such agreements by its statutory and regulatory structure (e.g., the need for legislative modifications), its inexperience in LNG negotiation, its status as a new entrant to the market, and the lack of an LNG supply portfolio to optimize. Risks associated with RIK could result in lower pricing for our LNG
  — Producers have more experience managing the exposures to market risk

• An election by the State to take its royalty in value presents potential for dispute on valuation and deductions and misalignment of interests with the Producers.
  — However, the State has experience in addressing these challenges through settlement agreements that provide more certainty and clarity
EXECUTIVE SUMMARY – KEY FINDINGS

Risk Allocation

• Oil and LNG prices and capital costs emerge as the key factors among the various risks impacting the AKLNG project’s economics

• Direct equity participation in the project can align the State with the Producers and reduce the cost structure of project for project sponsors but potentially exposes the State to additional risks

• Commercial terms related to equity participation such as position on the management committee and voting rights will determine the extent to which the State can achieve its objectives for open access and transparency
The AKLNG Project can be economically feasible and competitive with changes to the project’s cost structure and the State’s fiscal framework.

Fiscal and non-fiscal incentives can aid in improving the commercial attractiveness of the project:
- Fiscal – cost sharing, reduction in government take
- Non-fiscal – stabilization provisions, modifications to existing lease terms such as the notice period of the State’s rights to switch between RIK and RIV

Integrated project ownership of AKLNG by the Producers presents the risk of misalignment wherein project revenues could be moved between the upstream and the midstream components to maximize value to the Producers. These decisions could potentially be to the detriment of the State.
EXECUTIVE SUMMARY – CONCLUSIONS

• Fiscal structure changes beyond stand-alone royalty share or tax rate modification can help in improving project economics and creating alignment:
  — Direct participation by the State in the project
  — Establishment of a gross share of gas in lieu of production tax

• Direct state equity participation in the project can provide key benefits to the State including:
  — Create alignment of interests;
  — Create transparency through the midstream portion of the supply chain;
  — Facilitate third-party access to the mid-stream;
  — Potentially increase State cash flows, and improve producer economics.
Going further, establishment of a gross share of gas in lieu of production tax and corresponding equity investment in the project may provide the needed alignment for a competitive project such that the State can maximize the value of its resources.

The State has the ability to lessen project risk, but will need to weigh those opportunities circumspectly - risk mitigation and commercial agreements need to be addressed carefully to define the State’s rights and obligations, manage risk exposure and to achieve objectives of transparency and open access for third parties.
LNG MARKETS – SCOPE

- Overview of how LNG is being traded and valued in various markets that are available to AKLNG Project
- Analysis of historical and future global LNG pricing trends
- Discussion of supply and demand projections in the LNG market and implications for AKLNG Project
## CURRENT LNG MARKET REALITIES

### Demand/key markets
- Highly **concentrated** – 7 countries account for **70%** of demand
- Asia Pacific accounts for **70%** of global trade
- Growing rapidly – **8%** per annum over the past 5 years

### Supply
- LNG Supply is also highly **concentrated** – **8** exporting countries provided **83%** of global LNG exports in **2012**
- Liquefaction capacity is rarely developed on a speculative basis
  - Liquefaction facilities typically cost **US$5-20bn**
  - LNG facilities are generally **project financed**, requiring firm revenue commitments
  - LNG **specifications** vary by each project and between buyers

### Contracts/pricing
- Dominated by long term contracts (**LTCs**)
  - **~75% of global trade** was delivered under LTCs in 2011 and in 2012
  - Trade in Pacific basin is driven by LTCs more than in Atlantic basin
- **No liquid market** to provide price markers for LNG
- Price structure needs to give buyers and sellers reasonable certainty over **20 years**
- Oil/oil product price linkage has been standard since the **1970s**
- This link is usually defined in form of a **formula** with **slope to oil price** and **constant**

**SOURCE:** BP Statistical review of world energy; GROUPE INTERNATIONAL DES IMPORTATEURS DE GAZ NATUREL LIQUEFIE (GIIGNL), Team Analysis
**RECENT MARKET DYNAMICS: SUMMARY**

<table>
<thead>
<tr>
<th>Crude linked contracts</th>
<th>U.S. export contracts</th>
<th>Non price features/players’ responses</th>
</tr>
</thead>
<tbody>
<tr>
<td>• Crude linked contracts are signed by <strong>most suppliers</strong> excluding North American export terminals</td>
<td>• Emergence of <strong>Henry Hub linked</strong> US LNG tolling agreements has created an alternative to traditional crude linked contracts</td>
<td>• Apart from pricing, <strong>duration of contracts</strong>, the <strong>nature of commitment</strong>, <strong>delivery terms</strong> and LNG <strong>specifications</strong> are important features to be considered</td>
</tr>
<tr>
<td>– Between <strong>2002-2006</strong>, some <strong>low price contracts</strong> were signed by China/Japan</td>
<td>– <strong>Delivered LNG prices</strong> under these are currently <strong>lower</strong> than oil-linked contract prices</td>
<td>• Participants respond to <strong>supply and demand changes</strong> in a number of ways to <strong>protect the price floor</strong></td>
</tr>
<tr>
<td>– From <strong>2007</strong>, most recent contracts signed have a <strong>14% - 15% effective slope</strong> for the relationship of LNG price ($/Mcf) to crude price ($/Bbl)</td>
<td>– Buyers in countries such as <strong>Japan</strong> are <strong>increasingly asking for these</strong> and holding back on traditional contracts</td>
<td></td>
</tr>
</tbody>
</table>

**SOURCE:** Team Analysis
OUTLOOK FOR LNG DEMAND GROWTH VARIES ACROSS FORECASTING AGENCIES

Global LNG demand

CAGR 2010-20 (%)  CAGR after 2020 (%)

BP
5.0  4.2

Earnst & Young
6.1  2.3

GDF Suez
5.7  2.6

Reference case
5.1  2.6

Several agencies adopt a fast growth even after 2020

Our understanding of key differences

• Aggressive demand growth assumptions in Asia/new markets
• Growing or over-aggressive demand view on Europe
• High penetration of new gas demand sources such as gas for transport

1 Mtpa = 1.379 Bcma used

SOURCE: Public reports from or referenced information sourced from Wood Mackenzie; EY; BP; GDF Suez
## AKLNG: Present Value Share of Break Even Price (Zero NPV for Producers)

(2013 real US$/MMBtu), LNG price delivered ex ship (DES) in Asia

<table>
<thead>
<tr>
<th>Factors Impacting Break-even Price:</th>
<th>US$12.3/MMBtu is a conservative estimate subject to sensitivities</th>
</tr>
</thead>
<tbody>
<tr>
<td>Can increase the BEP:</td>
<td>• Lower ambient temperature advantage (currently assumed 3.0 Mtpa&lt;sup&gt;2&lt;/sup&gt;)</td>
</tr>
<tr>
<td></td>
<td>• Negative effect of reduced oil production (currently excluded)</td>
</tr>
<tr>
<td></td>
<td>• Capex increase, labor cost increase</td>
</tr>
<tr>
<td>Can decrease the BEP</td>
<td>• Capital productivity</td>
</tr>
<tr>
<td></td>
<td>• Lower returns</td>
</tr>
</tbody>
</table>

### Factors Impacting Break-even Price:

1. **Opex**
2. **Capex**
3. **LNG Plant**
   - **GTP & Pipe Costs**
   - **Shipping**
   - **State Take**
   - **Federal Take**
   - **Producer Present Value<sup>3</sup>**
   - **Break Even Price (BEP)**

### Costs:

<table>
<thead>
<tr>
<th>Costs</th>
<th>LNG Plant</th>
<th>GTP &amp; Pipe Costs</th>
<th>Shipping</th>
<th>State Take</th>
<th>Federal Take</th>
<th>Producer Present Value</th>
<th>Break Even Price (BEP)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Opex</td>
<td>0.6</td>
<td>0.4</td>
<td>1.0</td>
<td>0.5</td>
<td>1.0</td>
<td>0.2</td>
<td>0</td>
</tr>
<tr>
<td>Capex</td>
<td>3.4</td>
<td>3.2</td>
<td>0.6</td>
<td>1.0</td>
<td>0.5</td>
<td>1.0</td>
<td>12.3</td>
</tr>
<tr>
<td>Upstream Costs</td>
<td>1.0</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>LNG Plant</td>
<td>0.6</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>GTP &amp; Pipe Costs</td>
<td>0.4</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Shipping</td>
<td>1.0</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>State Take</td>
<td>0.5</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Federal Take</td>
<td>1.0</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Break Even Price (BEP)</td>
<td>12.3</td>
<td></td>
<td></td>
<td></td>
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</tr>
</tbody>
</table>

### Notes:

1. Discount rate used to calculate present value is 8.5% for mid-stream and 10% for upstream.
2. Effective ~17.4 Mtpa LNG capacity due to geographic advantage in Alaska.
3. Assumes contractor would take on a project where revenue matches its costs, including expected return on equity.

**Source:** Team Analysis
ON THE GLOBAL SUPPLY CURVE, AKLNG APPEARS TO CURRENTLY BE OUT OF THE MONEY, MODIFICATIONS REQUIRED FOR COMPETIVENESS

IMPLICATIONS:

1. **AKLNG** is currently out of the money:
   - Alaska break-even price is US$12.3/MMBtu
   - Projects more economic than Alaska can provide ~340 MTPA new supply, more than required to meet global LNG demand (~250 – 300 MTPA)

2. **AKLNG** faces significant competition
   - There are several projects to the right in supply stack which will compete with AKLNG

3. However, the risk levels of competing LNG projects also needs to be considered
   - Due to political, resource and other risks, some in the money projects may be delayed/cancelled, leading to range of needed capacity

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1. NPV=0 @ discounted at Weighted Average Cost of Capital

SOURCE: Team Analysis
While some existing plants are seeing decline in supply, there are several projects already under construction, mostly in Australia.

Approvals in lower 48 and Canada are adding to this supply fast.

Estimated ~50 Mtpa remaining opportunity to 2020 and ~30 additional Mtpa opportunity to 2025 after existing and projected approvals.
PROSPECTIVE FUTURE US LNG EXPORTS HAVE CREATED AN ALTERNATIVE TO TRADITIONAL CRUDE LINKED LNG CONTRACTING

A
JCC linked
- LNG from rest of world (Africa, Middle East, SE Asia, Australia)
- Fixed element, typically US$0-1/MMBtu

B
Henry Hub linked
- LNG export from US L-48
- Fixed element, typically US$3-4/MMBtu
- Henry Hub linked, typically 100-120% HH

Delivered price, Japan
$/MMBtu

Delivered price, Korea
$/MMBtu

AKLNG is likely to have a competitive advantage selling into the JCC-linked market

1 KOGAS-Cheniere 2012 example, actual contract is FOB, indicative shipping added
Note: US L-48 LNG exports have used a very different contract structure from the rest of the world and this results in lower delivered prices for expected oil and gas price levels
SOURCE: Team Analysis
IN THE LONG RUN THROUGH 2030, LNG MARKET CAN EVOLVE WITHIN A BROAD RANGE

### HIGH CASE
- North American LNG exports permitted at slow pace
- Non-NA Conventional supplies compete to serve the remaining demand
- Asian demand grows more rapidly than expected
- High cost LNG projects in Australia and Russia are the marginal supplies
- Sellers continue to demand high slope oil-linked contract terms

### LOW CASE
- North American LNG supply is unconstrained and can meet all uncontracted demand
- Low cost non-NA conventional supplies compete directly with North American exports
- Henry Hub linked US exports become the price setter for Asian LNG

**POSSIBLE PRICE RANGE**
- Typical price range for new Asian LNG contracts
  - US$14-18/MMBtu
  - US$10-14/MMBtu

**FACTORS AFFECTING**

SOURCE: Team Analysis
THE MOVEMENT OF LNG PRICES WITHIN THESE RANGES IS EXPECTED TO DEPEND ON THREE KEY FACTORS

**Supply-demand balance**
- Volume of LNG required
- Availability of LNG from planned and speculative sources (especially U.S./Canada)
- Break-even gas price of the marginal supply source

**Seller market power**
- Ability of major producers to maintain pricing discipline
- Ability and incentives of competing producers to undercut traditional price structures

**Buyer market economics**
- Competitiveness of LNG vs. other energy sources within the Buyers' market

SOURCE: Team Analysis
The LNG market is characterized by capital intensive projects and long-term contracts across the supply chain.

The LNG market is illiquid and opaque, with few players, in contrast with the liquid and transparent oil market.

LNG demand is expected to grow quickly over the short and long-term, but supply sources are also rapidly expanding.

AKLNG appears to be out of the money within the global LNG supply curve under the status quo; cost and/or fiscal modifications could enhance competitiveness.
SUPPLY CHAIN ELEMENTS – SCOPE

- LNG Markets
- Supply Chain Elements
- Fiscal Framework
- Risk Allocation & Fiscal Structure

- Overview of the current capital cost estimates for the AKLNG Project
- Review of the capital structures that are likely to be applicable to AKLNG Project
- Discussion and assessment of applicable commercial structures for AKLNG Project
### PROJECT CAPITAL COSTS UPDATE INCREASES BASELINE AKLNG PROJECT COST TO $45 BILLION (2013$)

**2008 Estimates**

<table>
<thead>
<tr>
<th>Supply Chain Element</th>
<th>2008 Estimate$^1$</th>
<th>2013 Updates</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>State’s Estimate</td>
</tr>
<tr>
<td>GTP</td>
<td>$5 Billion</td>
<td>$10 Billion</td>
</tr>
<tr>
<td>Pipeline</td>
<td>$8 Billion</td>
<td>$12 Billion</td>
</tr>
<tr>
<td>LNG</td>
<td>$14 Billion</td>
<td>$23 Billion</td>
</tr>
<tr>
<td>Total</td>
<td>$27 Billion</td>
<td>$45 Billion</td>
</tr>
</tbody>
</table>

$^1$ Capital cost for a 2.7Bcf/d LNG project estimated by the State’s Technical Team during AGIA proceedings.
## Capital Structures Vary from Project to Project Depending on Risk Profile and Partner Preferences

<table>
<thead>
<tr>
<th>Partners</th>
<th>Capital Structure (Debt/Equity)</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>ExxonMobil, Oil Search, Santos, National Petroleum Company of PNG, Nippon Oil, MRDC</td>
<td>70/30</td>
<td>Located at Caution Bay near Port Moresby, <strong>Papua New Guinea LNG</strong> is expected to have a capacity of 6.9 Mtpa and begin operations in 2014. PNGLNG is an integrated project and was the beneficiary of $8.3 billion in loans and guarantees from public export credit agencies.</td>
</tr>
<tr>
<td>Origin, ConocoPhillips, Sinopec</td>
<td>70/30</td>
<td>Two train design with a capacity of 9.0 Mtpa and requiring an investment of $23 billion, <strong>Australia Pacific LNG</strong>. Train 1 financed $8.5 billion. Origin operates the upstream segment of the project; ConocoPhillips operates the LNG facility.</td>
</tr>
<tr>
<td>Chevron, Shell, ExxonMobil, Chubu, Osaka Gas, Tokyo Gas</td>
<td>0/100</td>
<td><strong>Gorgon LNG</strong> is the world’s largest capital investment in an integrated LNG project. The $53 billion 15 mpta project is currently under construction and first LNG is expected in 2015. The project is financed through equity contributions from the partners.</td>
</tr>
<tr>
<td>Qatar Petroleum, ExxonMobil</td>
<td>70/30</td>
<td><strong>Qatargas 2 Train 1</strong> produces 7.8 Mtpa, Total is a partner in the second train, which also produces 7.8 Mtpa.</td>
</tr>
</tbody>
</table>

The Debt / equity ratio that the market can support for a given project is driven by the financial strength of the partners.
PRODUCER EXPECTATIONS OF ROE FOR INFRASTRUCTURE PROJECTS EXCEED FERC-APPROVED ROE FOR NEW BUILDS

Benchmarks for cost of equity:

- **15.0%**
- **12.0%**
- **12.0%**
- **11.7%**
- **9.7%**

- **Producer Expectations for Infrastructure Projects**
- **Utilities (TransCanada ask)**
- **FERC (New Build)**
- **FERC (Litigated Cases, Existing Pipelines)**
COMMERCIAL STRUCTURE OF PROJECT INFLUENCES RISK AND CONTROL

- **Integrated**
  - Aligned interest
  - Cost and risk sharing
  - Concentrated control

- **Merchant**
  - Less capital requirement for individual sponsors
  - Separation of control between upstream and LNG project

- **Tolling**
  - Contractually assured fees and returns
  - Accommodates supply from multiple upstream sources
  - No market upside for LNG project

Each structure affects the operations and financing costs of the GTP, pipeline, LNG plant, and the shipper and impacts key criteria important to State - Commercial viability of AKLNG project, open access, expandability, transparency across the supply chain.
LNG PROJECT COMMERCIAL STRUCTURES

Integrated LNG Project Structure

- One LNG Project Company
  - Same multiple sponsors in the upstream and liquefaction segments
  - Common ownership interests across the LNG chain
  - Sales and Purchase Agreement (SPA) directly between LNG Project Co and LNG Buyers – either FOB or DES
  - Examples: PNG, QatarGas II, RasGas, Sakhalin II, Tangguh

Non Integrated LNG Project Structure (Merchant)

- Legal Separation Between Sponsors of Upstream and Liquefaction Segments
  - Different shareholding interests between upstream, midstream and liquefaction
  - Gas Sales Agreement (GSA) between LNG Project Co/Borrower and Upstream shareholders
  - Examples: Peru LNG, QatarGas, NLNG (Nigeria), Brunei LNG

Tolling LNG Project Structure

- LNG Liquefaction Plant Performs Services For a Fee From Upstream
  - May have same or different sponsors in the upstream and LNG liquefaction facility
  - Usually limited recourse financing of LNG liquefaction facility with creditworthy tolling agreement counterparty
  - Examples: Egypt LNG, Atlantic LNG Trains 2-4

Sources: Sumitomo, B&V Research
## KEY CHARACTERISTICS OF LNG PROJECT STRUCTURES

<table>
<thead>
<tr>
<th>Structure</th>
<th>Advantages</th>
<th>Disadvantages</th>
</tr>
</thead>
</table>
| Integrated  | • Equity owners may or may not act together to sell the LNG product from an integrated structure  
• Control over production  
• Aligned interests between owners  
• Cost sharing and potential tax benefits | • Capital requirements are high and span the supply chain  
• Concentrated control makes expansions and entry of new participants difficult |
| Merchant    | • Lower capital requirement if sponsors of upstream and LNG Project Co are different  
• Meets tax requirements for separate P&L center  
• Comply with local laws for government ownership of upstream project  
• Less control by upstream participants over liquefaction facilities | • Less flexibility for equity participants in production of gas and selling LNG – sold uniformly by LNG Project Co  
• Commodity price risk exposure for LNG Project Co  
• Can be mitigated with variations of the merchant model, for example, by selling LNG back to project owners’ marketing affiliate to insulate the project from risk  
• Exposure to negotiating power of upstream owners |
| Tolling     | • Contractually assured fees and returns  
— Low market risk to LNG Plant Co  
— Mitigates upstream supply risk for LNG Plant Co  
• Potential tax benefits if title transfers are taxed  
• Accommodates supply from multiple sources, entities  
• Ability to attract other investors/owners to project – lower capital requirements  
• Facilitates project financing since liquefaction project revenues are not directly exposed to market risks | • No participation in market upside for LNG Plant Co |

State does not participate in upstream
COMMERCIAL STRUCTURE OF AKLNG PROJECT COULD DRIVE MISALIGNMENT BETWEEN THE STATE AND PRODUCERS

• A Producer-owned project creates risk for the State related to its fiscal revenues due to potential misalignment of interests between the Producers and the State.

• The misalignment could be especially pronounced at the LNG Plant which does not fall under FERC’s jurisdiction for establishing service rates.

• Under various alternate project structures contemplated, there could be incentive for Producers to shift revenues between the upstream and the midstream segment of the project, as a way of increasing Producer take (and thereby reducing the State’s take) from the project.

• This analysis examines a scenario where the LNG plant’s service rates are established using an equity-rich financing structure and with a relatively high return on equity.
IT IS CRITICAL TO CREATE ALIGNMENT BETWEEN STATE AND PRODUCER INTERESTS TO ENABLE STATE RECEIVING ITS FULL SHARE OF VALUE FROM THE AKLNG PROJECT

Equity-rich financing structure drives a high tariff for LNG Plant

<table>
<thead>
<tr>
<th>Financing Structure</th>
<th>Project Tariff</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reference Case 70% Debt; 30% Equity 12% ROE</td>
<td>GTP $2.40, Pipeline $2.40, LNG $6.73</td>
</tr>
<tr>
<td>100% Equity 14% ROE for LNG Plant</td>
<td>GTP $2.98, Pipeline $2.98, LNG $10.78</td>
</tr>
<tr>
<td>30% Debt; 70% Equity 14% ROE for LNG Plant</td>
<td>GTP $2.98, Pipeline $2.98, LNG $9.25</td>
</tr>
</tbody>
</table>

State could lose billions of dollars of value through misalignment

- Although the State could use regulations as potential safeguards, there is potential for misalignment of interests between the Producers and the State in a producer owned project
  - Areas of potential misalignment include need for transparency, open access and low tariffs
- Transparency within a producer-owned project into costs and cost allocation is likely to be an ongoing challenge for the State
- The risk of misalignment is higher with an LNG project than with a pipeline project driven by the absence of regulation of the LNG plant’s commercial structure or rate setting mechanism by FERC and other pertinent authorities
- Creating alignment between the State and Producers is critical for the State to receive the full value of the AKLNG project
Capital costs for AKLNG project are likely to remain uncertain through the development of the project

Total midstream project cost estimates from the AKLNG project sponsors range from $39-$54 billion

Complex LNG projects typically have an integrated commercial structure to give sponsors maximum control

AKLNG is expected to have an integrated structure; ensuring alignment of interests between the State and Producers is challenging and critical with a Producer-owned integrated project
FISCAL FRAMEWORK – SCOPE

- LNG Markets
- Supply Chain Elements
- Fiscal Framework
- Risk Allocation & Fiscal Structure

Overview of the fiscal structures relevant to LNG projects worldwide and comparison with AKLNG Project

Discussion and analysis of incentives that State could provide to help facilitate the AKLNG Project

Assessment of how Alaska can leverage its royalty ownership position – royalty in kind relative to royalty in value
THREE MAIN FISCAL SYSTEMS ARE IN USE FOR OIL AND GAS AROUND THE WORLD

<table>
<thead>
<tr>
<th>Fiscal system</th>
<th>Simple description</th>
<th>Examples</th>
</tr>
</thead>
<tbody>
<tr>
<td>Concessionary systems</td>
<td>• Title to the hydrocarbons transfers to the company at the wellhead. The host government receives royalties (% of revenues or production) and taxes (% of profits) from the company.</td>
<td>U.K.</td>
</tr>
<tr>
<td></td>
<td>• Title to hydrocarbons resides with host government</td>
<td>U.S.</td>
</tr>
</tbody>
</table>
|                                | • Production in kind is shared between the contractor and the government at the export point  
  − A basic PSC has royalty, cost oil, profit oil and taxes                                                                                           | Norway                    |
|                                | • Title to hydrocarbons resides with host government                                                                                                      | Australia                 |
|                                | • The contractor is reimbursed and paid a fee, typically in cash. These are rare and unpopular                                                            | Russia                    |
|                                |                                                                                                                                                                                                                     | Canada                    |
| Petroleum fiscal arrangements  |                                                                                                                                                                                                                     | Nigeria                   |
| Contractual systems           |                                                                                                                                                                                                                     | Angola                    |
|                                |                                                                                                                                                                                                                     | Russia                    |
|                                |                                                                                                                                                                                                                     | Algeria                   |
|                                |                                                                                                                                                                                                                     | Kazakhstan                |
|                                |                                                                                                                                                                                                                     | Indonesia                 |
|                                |                                                                                                                                                                                                                     | Qatar                     |
|                                |                                                                                                                                                                                                                     | Iran                      |
|                                |                                                                                                                                                                                                                     | Iraq                      |
|                                |                                                                                                                                                                                                                     | Mexico                    |
|                                |                                                                                                                                                                                                                     | Ecuador                   |
|                                |                                                                                                                                                                                                                     | Russia                    |

SOURCE: Team Analysis
GOVERNMENT TAKE ON LNG PROJECTS, BY COUNTRY

Government take for LNG projects generally falls within a wide 45%-85% range.
GOVERNMENT TAKE IN ALASKA IS BETWEEN 70%-80% UNDER SB21/MAPA FISCAL STRUCTURE WITH SIGNIFICANT FEDERAL GOVERNMENT SHARE

With current levies alone, government take is significant in the context of LNG projects worldwide

$328 Billion in Total Cash Flow
72% Government Share

$31.8 Billion in Total NPV
81% Government Share

* Negative NPV for YTF Fields of $-0.1B not shown
FISCAL & NON-FISCAL LEVERS ARE AVAILABLE TO INFLUENCE AKLNG PROJECT

<table>
<thead>
<tr>
<th>Sample levers</th>
<th>Benefits</th>
<th>Testing impact</th>
</tr>
</thead>
<tbody>
<tr>
<td>• Governments have multiple fiscal levers, e.g.,</td>
<td>• Results are:</td>
<td>• Effect:</td>
</tr>
<tr>
<td>– Replace royalty with profits-based tax</td>
<td>– Lower Government Take</td>
<td>Internal Rate of Return</td>
</tr>
<tr>
<td>– Accelerated depreciation</td>
<td>– Defer Government Take</td>
<td>Break-even prices</td>
</tr>
<tr>
<td>– Capital allowance (Deduct more than 100% of capex)</td>
<td>– Reduce cost exposure – increases IOC IRR</td>
<td>NPV</td>
</tr>
<tr>
<td>– Tax credits</td>
<td>– Reduce IOC Risk</td>
<td>Government take</td>
</tr>
<tr>
<td>– Enhance lifting entitlement</td>
<td></td>
<td>• Will help determine level of impact in attracting new investment</td>
</tr>
<tr>
<td>– Direct capital contributions</td>
<td></td>
<td>• Effect is difficult to see with financial metrics</td>
</tr>
<tr>
<td>• Governments have various non-fiscal options:</td>
<td>• Results are:</td>
<td></td>
</tr>
<tr>
<td>– Stabilizing provisions</td>
<td>– Reduce IOC Risk</td>
<td></td>
</tr>
<tr>
<td>– Intl. arbitration dispute resolution</td>
<td>– Enhance IOC comfort/confidence</td>
<td></td>
</tr>
<tr>
<td>– Increase IOC lifting entitlement (for booking barrels)</td>
<td>– IOCs should be more willing to invest</td>
<td></td>
</tr>
</tbody>
</table>

SOURCE: Team Analysis
### ELIMINATING ROYALTY, PRODUCTION TAX, OR PROPERTY TAX BRINGS GOVERNMENT TAKE FOR AK LNG PROJECT DOWN TO 65-70%

#### Share of Cash Flow

<table>
<thead>
<tr>
<th>Scenario</th>
<th>SOA</th>
<th>Federal Government</th>
<th>Producers (Midstream)</th>
<th>PBU + PTU (Upstream)</th>
<th>YTF (Upstream)</th>
<th>Producer (Upstream + Midstream) IRR</th>
</tr>
</thead>
<tbody>
<tr>
<td>0% Property Tax</td>
<td>$139</td>
<td>$136</td>
<td>$41</td>
<td>$70</td>
<td></td>
<td>16.3%</td>
</tr>
<tr>
<td>1% Property Tax</td>
<td>$151</td>
<td>$132</td>
<td>$44</td>
<td>$62</td>
<td></td>
<td>15.5%</td>
</tr>
<tr>
<td>No Royalty</td>
<td>$130</td>
<td>$139</td>
<td>$48</td>
<td>$71</td>
<td></td>
<td>15.8%</td>
</tr>
<tr>
<td>Half Royalty</td>
<td>$146</td>
<td>$134</td>
<td>$48</td>
<td>$62</td>
<td></td>
<td>15.3%</td>
</tr>
<tr>
<td>0% Production Tax</td>
<td>$119</td>
<td>$143</td>
<td>$48</td>
<td>$77</td>
<td></td>
<td>16.3%</td>
</tr>
<tr>
<td>15% Production Tax</td>
<td>$130</td>
<td>$139</td>
<td>$48</td>
<td>$70</td>
<td></td>
<td>15.9%</td>
</tr>
<tr>
<td>Base Case</td>
<td>$162</td>
<td>$128</td>
<td>$48</td>
<td>$54</td>
<td></td>
<td>14.8%</td>
</tr>
</tbody>
</table>

Producer (Upstream + Midstream) IRR
The analysis demonstrates that market prices dominate the AKLNG project’s economics dwarfing all other variables considered.

Royalty, property tax and production tax reductions are beneficial in improving Producer NPVs and IRRs from the project and reducing State take.

Overall government take impacts are dampened because ~35% of value transferred from the State to Producers goes to the Federal Government through federal income taxes.

To the extent that the State provides incentive to the AKLNG project through a value transfer, alternate mechanisms that reduce the leakage of this value to the federal government could be more effective in benefitting the AKLNG project.
ROYALTY ALTERNATIVES – IN KIND OR IN VALUE

• The State has an option of taking its royalty share from the AKLNG Project either in kind or in value

• Taking royalty in kind can be an incentive to Producers that potentially relieves their obligation to treat, transport, liquefy, ship and market the State’s share of gas, depending on the mechanism and location of transfer of gas to the State

• There are various considerations with regard to the State taking its royalty (or tax share) in kind that must be taken into account
## ROYALTY IN KIND VS. ROYALTY IN VALUE

<table>
<thead>
<tr>
<th>Royalty In-Kind</th>
<th>Royalty In-Value</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Advantages</strong></td>
<td><strong>Disadvantages</strong></td>
</tr>
<tr>
<td>• Attractive to producers</td>
<td>• Exposes State to various additional risks</td>
</tr>
<tr>
<td>• Reduces valuation disputes</td>
<td>• Requires modifications to current legislation and authority</td>
</tr>
<tr>
<td>• Reduces commercial uncertainty for project</td>
<td>• Requires marketing expertise</td>
</tr>
<tr>
<td>• Provides the State with better market insight</td>
<td>• Credit requirements for shipper agreements</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Royalty In-Kind</th>
<th>Royalty In-Value</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Advantages</strong></td>
<td><strong>Disadvantages</strong></td>
</tr>
<tr>
<td>• Status quo, familiarity</td>
<td>• Lack of transparency</td>
</tr>
<tr>
<td>• No direct firm capacity commitments</td>
<td>• No third party access (TPA)</td>
</tr>
<tr>
<td>• RIV auditing and management capabilities currently exist</td>
<td>• Valuation disputes: higher of; actual market price realized</td>
</tr>
<tr>
<td></td>
<td>• Gaming over cost deductions</td>
</tr>
<tr>
<td></td>
<td>• Not preferred choice of producers</td>
</tr>
</tbody>
</table>

Note: Equity participation with or without In-Kind Gas is another alternative for the State to consider and has been addressed separately

SOURCE: Team Analysis
RIK RISK PROFILE IS INFLUENCED BY THE LOCATION OF TITLE TRANSFER FROM THE STATE TO BUYER

Point Thompson/Prudhoe Bay → GTP → Pipeline → LNG → Shipping → Regas

**Risks:**
- Inlet GTP: Volume, Price, Capex (GTP), Operational risk (GTP), CO₂ disposal & gas quality, Balancing/scheduling, Credit risk (GTP), Force majeure
- Inlet Pipeline: Volume, Price, Capex (GTP+P), Operational risk (GTP+P), CO₂ disposal & gas quality, Balancing/scheduling, Credit risk (GTP+P), Force majeure
- Inlet LNG: Volume, Price, Capex (GTP+P+LNG), Operational risk (GTP+P+LNG), CO₂ disposal & gas quality, Balancing/scheduling, Credit risk (GTP+P+LNG), Force majeure
- FOB: Volume, Price, Capex (GTP+P+LNG), Operational risk (GTP+P+LNG), CO₂ disposal & gas quality, Balancing/scheduling, Credit risk (GTP+P+LNG), Force majeure
- DES: Volume, Price, Capex (GTP+P+LNG+S), Operational risk (GTP+P+LNG+S), CO₂ disposal & gas quality, Balancing/scheduling, Credit risk (GTP+P+LNG+S), Force majeure

**Rewards:**
- Inlet GTP: 15% JCC – S, − LNG – P
- Inlet Pipeline: 15% JCC – S, − LNG – P
- Inlet LNG: 15% JCC – S, − LNG – RP
- FOB: 15% JCC – S, − RP
- DES: 15% JCC

**Risk Premium:**
- Inlet GTP: .5% - 1.5%
- Inlet Pipeline: .25% - .75%
- Inlet LNG: .5% - 1.5%
- FOB: .25% - .75% (of JCC)
- DES: The risk premium is included in the JCC.

**Reward Amt:**
- GTP – RP
- RP

**Abbreviations:**
- GTP: Gas Treatment Plant
- P: Pipeline
- S: Shipping
- JCC: Japanese Crude Cocktail
- RP: Risk Premium

Source: Team assessment
IMPLEMENTING RIK PRESENTS CHALLENGES AND HENCE, COSTS FOR THE STATE RELATIVE TO RIV

NPV losses to the State from going RIV could be as much as 75% of value relative to RIV

<table>
<thead>
<tr>
<th>COST DRIVER</th>
<th>RIV</th>
<th>RIK</th>
</tr>
</thead>
<tbody>
<tr>
<td>GTP Costs</td>
<td>Only PBU is currently allowed to deduct GTP costs for royalty calculation</td>
<td>GTP costs will likely be borne by State for all fields</td>
</tr>
<tr>
<td>Upstream Field Cost Allowance (&quot;FCA&quot;)</td>
<td>PBU is currently allowed an Upstream FCA</td>
<td>Upstream FCA for all fields, potentially</td>
</tr>
<tr>
<td>Higher of Provision</td>
<td>Higher of provision creates price protection, offers ~3% uplift in royalty value</td>
<td>No higher of provision for price protection</td>
</tr>
<tr>
<td>Sales Price Discount</td>
<td>Theoretically, State achieves a portion of Producer’s full value</td>
<td>State expected to suffer discounted prices due to market inexperience and lack of diversity of supply; Discount to LNG sales price of the LNG multiplier in the 1% to 3% range examined as range</td>
</tr>
<tr>
<td>Marketing Costs</td>
<td>No marketing costs, but audit costs</td>
<td>Marketing costs of $7-$15 million a year</td>
</tr>
<tr>
<td>Credit Costs</td>
<td>Credit cost borne by Producers</td>
<td>Borne by State</td>
</tr>
</tbody>
</table>

![Diagram showing Royalty NPV10 (2013 Billions)](image)
RIK CREATES ADDITIONAL RISK AND COST FOR THE STATE RELATIVE TO RIV

• Taking its royalty in kind could potentially expose the State to significant risks including:
  — The State would need to build its own marketing organization to take care of origination, logistics, contract administration, accounting, etc. if it chooses to market the gas
  — State would face challenges in competing with the Producers who have well established LNG marketing expertise and global portfolios
  — State would be subject to counterparty risk in all of the contracts it enters into across the LNG supply chain
  — State would need to make firm capacity commitments along the LNG supply chain, which could total up to $1 billion per year
    • State could realize negative royalties if the LNG price is too low
  — State would face production volume risk (if production exceeds or falls short of its sales commitments)

• Producers have the experience of dealing with market uncertainties and would need to help the State address these risks if an RIK path is pursued
### SUMMARY: ALASKA FISCAL FRAMEWORK

1. Government take, at 70-85%, is high for a project of this complexity, and estimated IRR of approximately 15% may be insufficient for Producer investment relative to their alternatives.

2. Well designed incentives to lower project costs and modify fiscal structure can help make the AKLNG project competitive in market.

3. The State taking its royalty as RIK could result in a substantial increase in risk & potential loss of value for the State – Producers have more experience managing associated risks.
RISK ALLOCATION & COMMERCIAL STRUCTURE – SCOPE

- Overview of key risks that could impact the AKLNG Project stakeholders and risk management
- Assessment of alternatives for financial, equity participation by State in AKLNG Project

- LNG Markets
- Supply Chain Elements
- Fiscal Framework
- Risk Allocation & Fiscal Structure
THERE ARE VARIOUS UNCERTAINTIES RELATED TO THE AKLNG PROJECT THAT COULD IMPACT THE ECONOMIC BENEFITS TO THE DIFFERENT STAKEHOLDERS

AKLNG is exposed to risks beyond control of the State (and the producers)

- Prices
- Schedule
- Capital Cost
- Cost of Debt
- Escalations
PRICE AND CAPITAL COST RELATED UNCERTAINTIES EMERGE AS THE KEY FACTORS DRIVING THE PROJECT ECONOMICS

1 Base Price = $90/bbl oil price in $2013; LNG Price per MMBtu = 0.135*Oil Price + $1
High Price = $120/bbl oil price in $2013; LNG Price per MMBtu = 0.15*Oil Price + $1
Low Price = $60/bbl oil price in $2013; Henry Hub Price = $4/MMBtu in $2013; LNG Price per MMBtu = HH+$6
2 The escalation sensitivity captures a variation in the assumption related to annual change in capital costs, operating costs and oil and gas prices
RISK ALLOCATION AND MANAGEMENT

Cases of risk allocation

- Cost and time risks in project execution depend on the nature and extent of project organization apart from market factors
  - Of the recent LNG projects, most have a single operator for upstream, transport and liquefaction
  - Integrated project case has been successful in high cost project execution (Snøhvit case example)

Cases of risk mitigation

- Market risk management is executed by LNG projects in two ways:
  - Pre-FID commitments: Majority of project volumes are contracted before FID to ensure market. Example: Gorgon, APLNG
  - End user participation: Several projects have equity stake of end buyers providing ensured-market for corresponding equity volumes. Example: Tangguh, Sakhalin II

State participation and implications

- Where the Government participates in LNG projects is usually via NOCs with LNG majors who bring in LNG project experience
- State’s equity participation in the project can allow state to capture an upside in prices but exposes it further to a down-side
- Examples: Snøhvit, Yemen LNG, Angola LNG

SOURCE: Team Analysis
EQUITY PARTICIPATION BY THE STATE OF ALASKA COULD HAVE TANGIBLE BENEFITS FOR THE PROJECT AS WELL AS THE STATE

- To the extent that the State transfers value to the Producers through a modification of fiscal terms as an incentive for the AKLNG project, obtaining an equity interest in the project in exchange for that transfer of value is more beneficial to the State than a simple reduction in fiscal take.
- Greater alignment of economic interests between the State and Producers.
- State ownership lowers the upfront capital cost to Producers, creating potential economic uplift.
- Allows for TCPL equity participation and operation of the pipeline and GTP.
- Equity in all phases could facilitate greater transparency in the AKLNG Project.
- Allows State to influence access for third parties in the most critical potential bottlenecks of the project – pipeline and marine terminal.
- Equity investment in the supply chain, while allowing SOA a seat at the table, does not necessarily provide for a vote in the decision making process.
- Joint Venture Agreement structuring is critical.
ALTERNATIVES FOR THE STATE TO PARTICIPATE WITH AN EQUITY INVESTMENT IN THE AKLNG PROJECT – DESCRIPTION

Three different alternative structures for equity participation for the State were considered as indicative examples:

- **Equity Alternative**
  - The State makes an equity investment across the midstream and receives an equivalent share of gas produced as royalty and tax gas.
  - Royalties and production tax for oil would continue to be received under SB21/MAPA structure with all upstream costs being allocated to oil.
  - The analysis assumes a 70/30 debt equity structure for the State’s investment with a 5% cost of debt and a 12% return on equity.
  - Two different equity investment levels were considered as representing lower and upper bounds on the State’s equity participation – 15% and 35%.

- **100% State Ownership of Pipeline**
  - The State invests sufficient equity to entirely own the pipeline component of the midstream.
  - Producers would pay a tariff to the State for transportation services on the pipeline.
  - The Producers benefit from the State’s lower cost of debt at 5% and a low return on equity requirement of 6% (intended to be equivalent to returns on the Constitutional Budget Reserve Fund) provided as an incentive to the Producers.
  - The State would benefit through lower netbacks for royalty and production taxes.
  - To provide an upper and lower bound on the State’s contribution, the analysis examines two scenarios, one financed with 100% debt and the other with 100% equity.

- **12.5% State Ownership of Midstream**
  - The State invests to have a 12.5% equity stake across the midstream corresponding to an approximation of its royalty share.
  - The State’s share of the capacity would be utilized to treat, transport and liquefy royalty gas.
  - The State benefits from having a lower cost of debt at 5% and a low return on equity requirement of 6% (intended to be equivalent to returns on the Constitutional Budget Reserve Fund) rather than allowing a netback based on the Producers higher cost of debt and ROE requirements.
  - To provide an upper and lower bound on the State’s contribution, the analysis examines two scenarios, one financed with 100% debt and the other with 100% equity.
STATE EQUITY PARTICIPATION AT APPROPRIATE LEVELS COULD ALLOW SOA AND PRODUCERS TO RETAIN HIGHER SHARE OF PROJECT REVENUES

Stakeholder NPV$_{10}$ Comparison

<table>
<thead>
<tr>
<th>NPV $Billions</th>
<th>SOA</th>
<th>Federal Government</th>
<th>Producers PBU + PTU (Upstream)</th>
<th>Producers (Midstream)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Base Case</td>
<td>$32</td>
<td>$10.9</td>
<td>$15.0</td>
<td>$4.4</td>
</tr>
<tr>
<td>15% Equity Alternative</td>
<td>$32</td>
<td>$10.2</td>
<td>$15.5</td>
<td>$8.0</td>
</tr>
<tr>
<td>35% Equity Alternative</td>
<td>$31</td>
<td>$9.1</td>
<td>$15.1</td>
<td>$5.4</td>
</tr>
<tr>
<td>SOA Pipeline 100% Debt</td>
<td>$34</td>
<td>$10.1</td>
<td>$15.9</td>
<td>$6.4</td>
</tr>
<tr>
<td>SOA Pipeline 100% Equity</td>
<td>$30</td>
<td>$10.1</td>
<td>$13.0</td>
<td>$6.4</td>
</tr>
<tr>
<td>12.5% SOA 100% Debt</td>
<td>$32</td>
<td>$14.6</td>
<td>$17.0</td>
<td>$3.7</td>
</tr>
<tr>
<td>12.5% SOA 100% Equity</td>
<td>$31</td>
<td>$14.6</td>
<td>$15.7</td>
<td>$3.7</td>
</tr>
</tbody>
</table>

% Producer (Upstream + Midstream) IRR

14.8% 17.7% 16.6% 17.2% 16.8% 14.6% 14.6%
Appropriate level of state equity participation needs to be balanced to achieve benefits to SOA and producers

- Scenarios examining a range of capital costs and market prices were assessed to understand whether the equity alternative provides positive economic value to the State relative to status quo under each of the scenarios.

- 15% and 35% state equity participation levels in combination with equivalent royalty gas & tax gas were considered as indicators of lower and upper bounds to the State’s equity participation.

- SB21/MAPA fiscal structure as currently applicable does not include production credits for gas. This analysis assumes a modified status quo wherein the production credits are extended to reflect a $5/BOE credit for gas, similar to the credit extended to new oil production.

- The analysis estimated and compared AKLNG project economics under modified status quo and under the equity alternative for both the State and the Producers across a combination of three price and three capital cost scenarios.
EQUITY PARTICIPATION AT 35% MORE BENEFICIAL TO STATE THAN AT 15%

15% SOA equity participation – $NPV_{10}$

State of Alaska Total NPV$_{10}$

35% SOA equity participation – $NPV_{10}$

Producer (PBU + PT) Total NPV$_{10}$
STATE EQUITY PARTICIPATION BETWEEN 20% AND 30% OFFERS \( NPV_{10} \) AT OR ABOVE THE MODIFIED STATUS QUO LEVELS FOR THE STATE

The level of State equity investment required to equal total state \( NPV_{10} \) under status quo varies with market conditions.
SOA EQUITY INVESTMENT IN AKLNG CREATES RISK EXPOSURES THAT NEED TO BE CONSIDERED AND MANAGED

- Cost overruns and cash calls above appropriation level – To the extent that the actual Capex exceeds the budgeted amount the State of Alaska is expected to be responsible for its pro-rata share of the increased costs. This is a significant risk for the State of Alaska given the high cost structure of the AKLNG Project and likely inflationary pressures.

- As an equity owner, the State assumes all Force Majeure risk throughout the GTP, pipeline and LNG terminal.

- State has no control over upstream operations and volumes produced by the Producers
  - Could have excess or insufficient capacity relative to volumes produced
  - Balancing production volumes and volumes through the supply chain on a short-term and long-term basis

- If the State assigns its equity position to a third party such as TransCanada and contracts for capacity with this third-party, the State will likely have to provide credit support to the entity that would assume the state’s equity share in the midstream through long-term commitments for capacity.

- State would be responsible for all demand charge obligations throughout the life of the contract regardless of gas supply availability and market conditions
  - Possible that revenues earned on LNG sales would not offset costs of treating, transport and liquefaction resulting in negative cash flows to the State.
ENSURING TRANSPARENCY & OPEN ACCESS WILL DEPEND ON THE ACTUAL TERMS NEGOTIATED FOR STATE PARTICIPATION

<table>
<thead>
<tr>
<th>Commercial Design Option</th>
<th>Implementation to Achieve ...</th>
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<tbody>
<tr>
<td></td>
<td>Transparency</td>
</tr>
<tr>
<td>Equity participation</td>
<td>✓ Each Segment</td>
</tr>
<tr>
<td>Position on management committee</td>
<td>✓</td>
</tr>
<tr>
<td>Participation through secondees on GTP, Pipeline and LNG plant teams</td>
<td>✓</td>
</tr>
<tr>
<td>Undivided joint interest approach “pipe within a pipe”</td>
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<tr>
<td>Expansion rights to be negotiated within context of JVA</td>
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</tbody>
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SUMMARY: RISK ALLOCATION & COMMERCIAL STRUCTURE

1. AKLNG faces various risks that could affect the economic benefits; prices and capital cost are key.

2. Direct equity participation by the State can offer benefits to all parties involved in the project; accompanying risk profile changes should be managed.

3. Various commercial terms related to equity participation will determine whether the State can achieve its transparency and access objectives.