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ALASKA LNG: KEY ISSUES

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WHAT IS THE LEGISLATURE WEIGHING THIS SESSION?

Governor Sean Parnell has proposed to the 28th Legislature a package that includes Senate Bill 138 (also introduced into the House as HB 277). The bill is the **first in a series of actions** to be taken over the next four to five years to allow for the development of Alaska's gas resources on the North Slope. In December 2013 and January 2014, the State of Alaska signed **two cornerstone agreements** that offer a blueprint for how North Slope gas will be developed: a Heads of Agreement (HOA) and a Memorandum of Understanding (MOU). The currently **envisioned endpoint** of these two agreements and SB138 is a project consisting of:

- A gas treatment plant on the North Slope to make the gas ready for transport
- A large scale, 42-inch gas pipeline from the North Slope to Nikiski in Kenai
- A 15-18 million ton per annum liquefied natural gas (LNG) export facility at Nikiski
- At least five off-take points for gas consumption within the state

These assets collectively form **Alaska LNG (AK LNG)**; Steve Butt (of ExxonMobil), the project's manager, discussed the details in a Lunch & Learn Session in Juneau on February 4, 2014 (video). The HOA and MOU outline a scenario to allow for the **State of Alaska to be a part-owner (equity participant) in AK LNG**, thus sharing in the risk and the reward in a similar fashion to the private sector companies.

While the HOA and MOU are largely non-binding and set out a vision for the project, SB 138 is 'enabling legislation' that authorizes the administration to negotiate firm contracts with the parties to the HOA and MOU.

Heads of Agreement (HOA). An HOA is "A non-binding document outlining the main issues relevant to a tentative partnership agreement. Heads of agreement represents the first step on the path to a full legally binding agreement or contract, and serves as a guideline for the roles and responsibilities of the parties involved in a potential partnership before any binding documents are drawn up" (definition from Investopedia).

The HOA is dated January 14, 2014 and includes six parties: (1) The Administration of the State of Alaska; (2) The Alaska Gasline Development Corporation; (3) TransCanada Alaska Development Inc.; (4) ExxonMobil Alaska Production Inc.; (5) ConocoPhillips Alaska, Inc; (6) BP Exploration (Alaska) Inc.

The HOA outlines a vision for the state to become an investor in the Alaska LNG project

The HOA outlines a broad intention for the State of Alaska to participate in AK LNG as an equity partner rather than simply as a collector of royalties and taxes based on the value of the gas on the North Slope. The HOA proposes that, if satisfactory agreements can be reached, the state would take its gas entitlement from royalty and production taxes on Prudhoe Bay and Point Thomson in the form of gas instead of cash. The state would then take a corresponding ownership stake in the AK LNG project, contributing its share of the construction costs, while sharing in the revenues generated by this project. The HOA envisions that the state would own 20-25% of the gas and infrastructure associated with this project.

Memorandum of Understanding (MOU). An MOU is "A legal document outlining the terms and details of an agreement between parties, including each parties requirements and responsibilities" (definition from Investopedia).

The MOU was signed on December 12, 2013 and is an agreement between the State of Alaska and two companies: TransCanada Alaska Company and Foothills Pipe Lines LTD (a fully owned subsidiary of TransCanada). The MOU concerns the pipeline and gas treatment plant (GTP) components of the AK LNG project, but not the LNG (liquefaction) facility.

The MOU deals with the GTP and pipeline parts of the project and provides terms for bringing TransCanada in as a partner in AK LNG

Under the MOU, the state would assign to TransCanada the 20-25% equity share in the GTP and pipeline provided for the state under the HOA. TransCanada would bear the state's share of the pre-construction and construction costs for the GTP and pipeline, and the state would then pay TransCanada a tariff to ship its own gas through these facilities. The MOU lays out the terms that would govern the transportation contract between the state and TransCanada, including the basis on which the tariff would be set.

The MOU also gives the state an option to buy back 40% of its original share in the pipeline and GTP from TransCanada (thus ending up with a 6 to 10% share, given that TransCanada's share cannot fall below 14%). The state has until December 31, 2015 to exercise this buyback option by reimbursing TransCanada the corresponding share of its development expenses to date with interest (for example, if TransCanada has paid $100 million, the state would pay 40% of this amount, $40 million, plus interest).

The table on the next page summarizes the possible pathways envisioned by the HOA and the MOU together, and how they contrast with the status quo.

	PARTICIPATION	STATE OWNERSHIP		
	ROYALTY & PRODUCTION TAX	UPSTREAM	GTP & PIPE	LNG
STATUS QUO	IN VALUE & NO OWNERSHIP	0%	0%	0%
HOA	IN KIND & EQUITY OWNERSHIP	0%	20-25%	20-25%
MOU & BUYBACK	IN KIND & EQUITY OWNERSHIP	0%	6-10%	20-25%
MOU & NO BUYBACK	IN KIND & EQUITY OWNERSHIP	0%	0%	20-25%

SB 138 both authorizes certain negotiations and provides a broad roadmap for how the Legislature will oversee and consent to these negotiations

SB138. SB 138 forms the 'enabling legislation' that provides the statutory framework and relevant authorities to negotiate detailed contracts that cement the vision laid out in HOA and the MOU. The bill provides:

- A **gross, rather than a net-profit-based production tax on gas,** with the option in certain circumstances for the tax to be paid in kind, with gas, rather than in value. By electing to take both royalty and gross production tax on gas from Prudhoe Bay and Point Thomson in kind, as gas instead of cash, the state would achieve a 20-25% share of the total gas for the project.
- Empowers the administration to **negotiate contracts** with the companies on a wide range of areas including the off-take and balancing of gas from the producing fields, transportation and liquefaction services, and marketing of the state's LNG. These agreements would translate the broad vision of the HOA and MOU into a firm project structure.
- **A broad roadmap for how the Legislature will oversee and consent to these negotiations.** Legislators would be kept informed and have the ability to provide feedback during the negotiations through briefings held in executive session, with final contracts returning to the legislature, in public, for approval.

This is a long-term process with several decision points (and off-ramps) and progressively greater demands for capital. If all goes well, AK LNG could be online in the early 2020s.

Project timeline. These agreements provide the basis for a long-term process to bring North Slope gas to the market.

The first step in this process would be to conduct a pre-FEED (Front End Engineering and Design) study, through which the various participants would define in greater detail the form that this project will take. Pre-FEED studies have both a technical and commercial component since both are essential for project success. This process could take 1-2 years and could cost $400 to 500 million (paid by all the project owners together, each funding their proportional share).

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Project Stage	Pre-FEED		FEED				Construction				Online		
Investment (Project)	$400–$500 mm		$1,500–$2,000 mm				$45–65 billion (Debt and equity)				Cash covers debt and other expenses		
Investment (SOA)	$50–$125 mm		$200–$500 mm (Equity)				$6–$15 billion (Debt and equity)				Cash covers debt and other expenses		

If the results of the pre-FEED are successful and all the parties are satisfied that this is a viable project that meets their commercial and strategic objectives, **the parties will then proceed to a detailed FEED study, which will further define the technical, legal and commercial aspects of this project to a great degree of procession** (blueprints, negotiations with suppliers and with buyers, preliminary agreements for finance, export permits, environment approvals, etc.). This phase could cost $1.5 to $2 billion and last 2-3 years.

At the completion of the FEED study, the parties will weigh whether to sanction the project—or take 'final investment decision' (FID) in the industry's parlance. FID is the most important milestone because it marks a "green-light" authorization for the project to start construction and for the parties to invest more substantial amounts of capital in the project (at this point estimated between $45 and $65 billion). Construction usually lasts 4-5 years.

All parties must agree to move from one stage to the next and so each party can assess, at every point, whether the project is proceeding according to its interests.

DOES ALASKA NEED AN EXPORT PROJECT?

In-state demand is too small to absorb the enormous gas resources on the North Slope

Alaska's gas resources are sizable: Prudhoe Bay and Point Thomson, the largest accumulations of discovered gas on the North Slope, contain 35 trillion cubic feet (tcf) of gas. Moreover, the United States Geological Survey estimates that the North Slope could contain 244 trillion cubic feet (tcf) of undiscovered recoverable gas resources (of which 99 tcf is conventional and 145.5 tcf is unconventional gas). Beyond the North Slope, the Bureau of Ocean Energy Management estimates that Alaska's Arctic subregion (the Chukchi Shelf, the Beaufort Shelf and the Hope Basin) could hold another 108 tcf of gas.

By contrast, according to the According to the Energy Information Administration (EIA) at the Department of Energy, **Alaska consumed 641 trillion British thermal units (BTUs) in 2011, which is roughly the same as 641 billion cubic feet of gas equivalent demand**. In other words, even if it were theoretically possible for Alaska to run its entire economy on natural gas (including using gas to generate jet fuel for use in aviation, one of the state's biggest energy consuming sectors), the gas at Prudhoe Bay and Point Thomson alone could suffice to meet the state's demand for over 40 years without needing to develop any more gas fields (including at Cook Inlet). In reality, given constraints on the ability to substitute gas in transport and other sectors, it would take far longer to consume the gas from these fields, before even considering the rest of the likely resource base. Therefore, for the state to fully develop the discovered gas on the North Slope, as well as provide incentives for additional exploration and development, Alaska needs to find export gas.

WHY EXPORT THE GAS AS LNG?

Given the need to export gas, Alaska has many options to monetize this gas.

The United States uses 6 bcf/d of gas in chemicals; Alaska is unlikely to develop a chemicals industry big enough to use all of its gas

Gas to chemicals for export. Several countries have developed a value-added industry based on gas as a feedstock for petrochemicals. The question is not whether Alaska should develop such an industry but whether this industry is a sufficient stand-alone option to utilize the state's enormous gas resource. According to the EIA's Manufacturing Energy Consumption Survey, the US chemicals industry consumed about 6 billion cubic feet a day (bcf/d) in 2010. Moreover, this industry supported 774,000 full-time equivalent employees in 2010 according to the Bureau of Economic Analysis at the US Department of Commerce. Connecting these two pieces of information, it is clear that **Alaska is too small in terms of its population to develop a petrochemical industry of the size that could fully use the state's gas resources**, even (generously) assuming that petrochemicals from North Slope gas, once all the costs are included, could be competitive.

Alaskan power from the North Slope would be hard pressed to compete in Canada

Gas used to generate electricity on the Slope for export. Ignoring, for simplicity, the substantial losses associated with transmitting electricity over hundreds of miles, the question is: to where could Alaska export any electricity generated on the North Slope? The obvious answer is Canada. But the provinces closest to Alaska, Yukon and the Northwest Territories, produced in a year less electricity than Alaska generated in a one month alone (424 GWh in 2011 vs.

Alaska's 591 GWh in December 2013). As such, exports would have to move deeper into Canada to British Columbia (BC). BC generated 66,395 GWh in 2011, but the province's power mix is heavily dependent on hydro (87% of installed capacity in 2011). And the region has ample gas resources that it is looking to export. **The proposition of generating gas-based electricity in the North Slope and ship this electricity to Canada is thus highly questionable.**

Alaska would need to build more GTL capacity than exists in the world today to use 2 bcf/d of gas

Gas to liquids (GTL) for export. A few years ago, companies were very interested in GTL, but this interest has dissipated, partly due to uncertain economics and severe overruns. There are only a few operational plants in the world (see table).

EXISTING LARGE-SCALE GAS TO LIQUIDS PLANTS

PLANT NAME	COUNTRY	OPERATOR	START-UP	CAPACITY MB/D
MOSSEL BAY GTL	SOUTH AFRICA	PETROSA	1992	30,000
BINTULU GTL	MALAYSIA	SHELL	1993	14,700
MOSSEL BAY GTL EXP.	SOUTH AFRICA	PETROSA	2005	15,000
ORYX GTL PHASE 1	QATAR	SASOL/QP	2006	32,400
PEARL GTL PHASE 1	QATAR	SHELL	2011	70,000
PEARL GTL PHASE 2	QATAR	SHELL	2011	70,000
TOTAL CAPACITY				232,100

SOURCE: CRAIG BROWN, GAS-TO-LIQUID, OXFORD INSTITUTE FOR ENERGY STUDIES WORKING PAPER

Assuming a 20% loss in the conversion of gas to liquids, Alaska would need to develop GTL capacity of some 267 mb/d in order to commercialize 2 bcf/d of gas (the size of the proposed LNG project). In other words, **a GTL option would require that Alaska become home to over half of the world's GTL capacity and assume technical and commercial risks that many oil companies eschew.** Alaska would also need a solution to transport the premium products, since these could not currently be shipped through TAPS. While a smaller domestic GTL solution could make sense, this is not a feasible large-scale export option.

Exporting gas via pipeline to markets in surplus is a losing proposition

Gas exports via pipeline. Alaska has a long history of exploring a pipeline option for selling gas to Canada and the Lower 48. **But in today's market environment, where both Western Canada and the Lower 48 have surplus gas and are looking to export LNG, such a proposition seems to have little commercial merit, as evidenced by the collapse of the Alaska Pipeline Project**.

The major North Slope producers have concluded that LNG is the option that deserves most attention right now

Gas exports via LNG. A large-scale LNG plant is the most obvious option to develop the existing and yet-to-find resource, provided that the infrastructure can be constructed at a cost which the market can bear. The technology is well understood and the market is also well established, which is one reason why the three producers (ExxonMobil, BP, ConocoPhillips) think that this option is most likely to maximize the value for their shareholders. **As a proven, highly scalable technology, LNG is also the only potential solution with clear avenues for expansion that could enable the commercialization not just of Alaska's existing resource base, but also of a yet-to-find gas resource which could easily dwarf that which is currently known.**

WHY MIGHT THE STATE CONSIDER INVESTING IN AK LNG?

Sovereigns invest in LNG projects in their territories in the majority of countries where LNG is produced

Many different means of state participation. Governments generate value from LNG projects in many ways. Some, like Australia, Canada and (to date) the United States act solely as taxing and permitting/regulating authorities. The majority of countries, however, have some form of ownership in the LNG ventures in their territories, and some countries such as Malaysia, Qatar and Algeria, often invest in associated facilities overseas (shipping, regasification, etc.), and take active roles in overseeing and managing LNG projects.

States that invest actively in LNG do so because they understand that gas in the ground is worth only a modest amount; only through liquefaction, shipping, sales and marketing can that gas to be sold for premium prices in markets where the demand is highest, and so those states maximize the value they receive by participating in these value-adding parts of the chain.

Because gas trades at a thermal discount to oil and because it is more expensive to transport, a purely tax-based approach would expose the State of Alaska to considerable price and cost risk

Low value at the point of production. Alaska currently generates value from its hydrocarbons through royalties and a production tax based on the 'Gross Value at the Point of Production' (the value shortly after the resource leaves the wellhead). While this system works for oil, it is more problematic for gas because gas is considerably harder and more expensive to transport.

The following table compares the Gross Value at the Point of Production for oil and gas. **For oil, the total tariff to move a barrel of North Slope oil to the US West Coast is around $10/bbl** (this includes both the Trans-Alaska Pipeline System, TAPS, and marine transportation), resulting in **gross value at the point of production of approximately $90 when the ANS West Coast price is $100.** To examine the equivalent value for gas, we start with the fact that 6 million British thermal units (mmbtus) of gas, 6 thousand cubic feet (mcf) of gas and one barrel of oil all contain approximately the same amount of energy; so 6 mmbtus or 6 mcf both equal one 'barrel of oil equivalent' (boe). Gas in Asia is generally priced based on some form of indexation to crude oil, but usually at a discount, so that when the price of Alaska North Slope (ANS) crude is $100/bbl, the price LNG in Japan under a typical contract might instead be $81/boe. Moreover, transporting a barrel-equivalent amount of LNG to Asia could easily cost as much as $66/boe, based on current cost estimates for AK LNG. Therefore, **when all costs are netted out, the remaining value at the 'point of production' is only a small fraction of the sale price of the LNG.**

INDICATIVE VALUE CHAIN IN ALASKA: OIL VS. GAS	OIL ($/BBL)	GAS ($/BOE)
RESOURCE PRICE	$100.00	$81.00
LESS: MARINE TRANSPORTATION	$3.46	$6.00
LESS: PIPELINE (& LIQUEFACTION) TARIFF	$6.58	$60.18
GROSS VALUE AT POINT OF PRODUCTION	$89.96	$14.82

More importantly, because the transportation tariff is so high and is a fixed component, **a 10-15% fall in prices or rise in costs could wipe out the wellhead value of Alaska's gas altogether. Thus, if Alaska generates value**

gas by taxing and collecting royalties based on the value at point of production, it will take a high degree of price and cost risk. If the project is within budget, and LNG prices are high, the state will do well. But if costs are higher or prices lower than anticipated, the value to the state will quickly be wiped out, because all value will be consumed by the 'midstream' transportation components of the value chain.

By investing in the project, the state avoids a repeat of the valuation disputes that plagued TAPS and provides the long-term certainty that all the partners need in order to sanction the project

Alignment. Not only do these transportation costs represent the majority of the value of the LNG, they are also likely to be very opaque. The liquefaction project, in particular, will be subject to minimal regulatory oversight, with much freedom for the liquefaction owners to structure the project and set a tariff as they see fit. By financing the liquefaction facility mostly through equity rather than debt, for example, the owners could potentially raise the tariff even further, costing the state billions in forgone tax and royalty revenues over time. The state has much experience with difficult disputes over tariffs for TAPS; **when tariffs consume the overwhelming majority of the barrel, as they do in LNG, the potential for dispute could become an insurmountable barrier for the project.**

For their part, the existing North Slope producers have also been burned by the disputes of the past. LNG is a business that requires long-term certainty and stability because LNG typically requires a long payback period to cover the high upfront investment. No investor will commit the amount of capital that this project requires ($45-65 billion) without knowing that the terms of the game will not change later due to disputes with the state. **Without certainty and stability, this project will not go ahead.**

The producers could achieve such stability solely through contracts with the state, but their terms would likely be unacceptable to the state. Instead, the producers can achieve stability through alignment by partnering with the state as an investor in the project. As a co-investor, **the state would generate value the same way the producers do**. When the producers do well, the state would do well. Since the state would have similar long-term commitments as the producers, **it would need stability in exactly the same way**. **The potential for disputes over items like tariffs would be eliminated, because the state would no longer face a tariff for transportation as such. Instead, the state would simply own a share of the gas, and corresponding share of the infrastructure required to move the gas to market.**

Equity protects the state better. Intuitively, one would think that if the state were to take a 25% share of the AK LNG project, it would be taking substantially more price and cost risk than if it simply took taxes and royalties from the project. One might also think that by taking 25% of the equity, it was only capturing 25% of the value of the project, while the North Slope producers captured the lion's share of the value. Both of these intuitions, however, are incorrect.

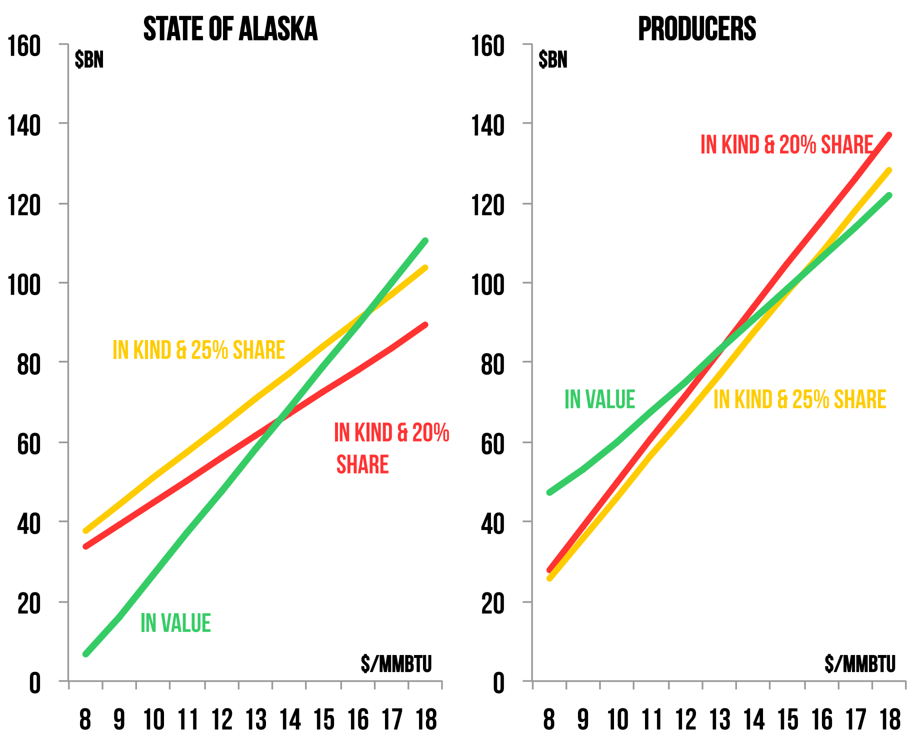
We have already shown that for gas, value at the point of production is low and variable, while the cost of transportation is high and "fixed" (in the sense of a fixed tariff). As a result, if the state is a wellhead-value taxing authority, taking its share 'in value', small movements in price or cost can wipe out value to the state altogether. The fixed midstream costs amplify the impact of price and cost movements on the state. Returns to the midstream are effectively 'guaranteed' in most circumstances, while the upstream, where the state draws its value, is the 'shock absorber' and takes up almost all of the risk. When prices fall (see table below), the midstream part still earns the same value but the gross value at the point of production shrinks.

INDICATIVE LNG VALUE CHAIN IN ALASKA	GAS ($/BOE)	GAS ($/BOE)	GAS ($/BOE)
RESOURCE PRICE	$70.00	$75.00	$81.00
LESS: MARINE TRANSPORTATION	$6.00	$6.00	$6.00
LESS: PIPELINE (& LIQUEFACTION) TARIFF	$60.18	$60.18	$60.18
GROSS VALUE AT POINT OF PRODUCTION	$3.82	$8.82	$14.82

Counterintuitively, the state is better protected on the downside by taking equity; it also takes more than 25% of the project value even though its share is only 25%

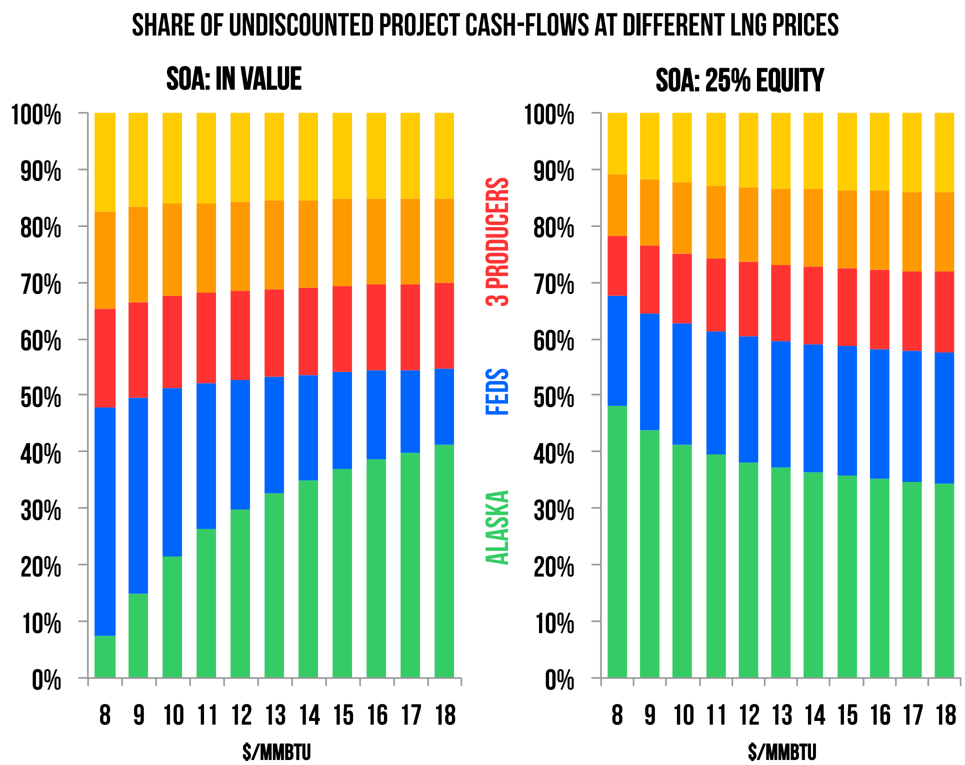
By taking a 25% share of the gas 'in kind' for the project, and 25% of the equity, the state removes this fixed component and draws value from the entire chain. **If gas prices fall, the state's return on investment would fall, but because it participates throughout the value chain, its revenues would fall less than if it were only an upstream taxing entity.** The cost of this protection is that by participating 'in kind', the state must contribute more cash up-front to project development, and in a high-price world, it will capture less of the upside than it would as an 'in value', taxing authority.

TOTAL UNDISCOUNTED PROJECT CASH-FLOWS TO STATE AND PRODUCERS AT DIFFERENT LNG PRICES



Overall, however, **the state receives a share of project value that is higher than its 25% share**. In fact, on average, across a range of gas prices, with a 25%

equity share, the state would capture a share of value roughly equivalent to that of all three of the producers combined (who own 75% of the project). The state is able to do this because of its advantages with respect to taxes. While the three producers must pay state income taxes and property taxes to the state (increasing the state's share), and must also pay federal income tax, the state does not pay these taxes other than to itself (including, within its remit, municipalities).



WHAT ROLE DOES TRANSCANADA PLAY?

Under the Heads of Agreement (HOA), the state would acquire a 20-25% share of the gas for the AK LNG project, and would carry a corresponding 20-25% of the equity in the project. As an equity partner, it would be responsible for 20-25% of the costs of developing the $45-$65 billion project.

The Memorandum of Understanding (MOU) assigns the state's 20-25% ownership in the gas treatment plant (GTP) and pipeline to TransCanada (TC), while retaining the state's full share in the liquefaction component of the project. The state would also have the option to reclaim up to 40% of its original share in the pipeline and GTP from TC by repaying the corresponding share of TC's development expenses to date with interest.

If the state is capital constrained, divesting part of its share in the GTP and pipeline make more sense than reducing its ownership of the liquefaction plant

Concentrating state share in liquefaction. Key to the approach entailed under the MOU is a distinction between the pipeline and GTP components of the project, and the liquefaction plant. There are a number of reasons why such a distinction might make sense.

Of all of the components in the project, the liquefaction plant will be the most expensive (likely constituting around half of the total project cost), the least subject to regulatory oversight, and the least transparent to non-participants. As a result, the **liquefaction plant presents the greatest potential source of lost value to the state if it does not participate in that component of the project.** By contrast, regulated, cost-of-service tariff-setting principles are well established for pipelines in the United States, and it is possible to set a transparent tariff for a pipeline that provides a set return to a third-party pipeline company.

If the state proceeds with equity participation in AK LNG, it will generate the greatest possible value in most circumstances through the greatest possible share of the overall project. The overall share the state can take, however, is constrained by two factors: by the size that the producers are willing to agree to (if the state share is too large, there will be insufficient value for the producers to find the project attractive); and by the state's ability to finance its share of the construction costs.

Given such constraints it may make sense for the state to reduce its exposure to lower-yielding project components in order to carry the largest possible share in the higher-yielding components that lies within its financial capacity. **So long as an attractive tariff can be established for the pipeline and GTP, reducing the state's exposure to these components, and maximizing its participation in the liquefaction facility may make sense if the state is capital-constrained.**

In this regard, from a purely financial perspective, the impact of TC's involvement may be seen as being akin to a loan; it reduces the capital investment in the project required of the state, and the state pays back the 'loan' through a fixed payment in the form of a tariff. Also like a loan, it increases some of the state's exposure to risk by adding a fixed claim on the project cash-flows that must be met before the state receives its share. Compared to other forms of debt, TC's involvement is a relatively expensive form of financing, with a weighted average cost of capital (WACC) that is significantly above the state's own cost of debt. However, since there will likely be limits on the amount of debt that the state is able to carry for the project, the ability of TC to shoulder some of the burden may still be attractive. This may particularly be the case because of other benefits TC's involvement in the project can offer.

A third-party pipeline company increases the odds that the infrastructure can be expanded to include new gas discoveries for delivery to Alaskans as well as international markets

Expansion benefits of a third-party participant. The existing producers have a clear and demonstrated execution capability to undertake the pipeline and GTP components of AK LNG alone. However, since the potential North Slope gas resource base is likely much larger than just existing reserves at Point Thomson and Prudhoe Bay, the question of how future expansions of the AK LNG project are handled will also be critical. The interests of the state may well differ in this regard from the interests of the existing major North Slope producers.

The producers will ultimately generate income from AK LNG by selling gas that they own into premium export markets. They have no compelling interest in ensuring the ability of other North Slope resource holders to monetize their own gas by expanding the AK LNG facilities. While they might support an expansion that reduced their own unit costs, they are unlikely to devote significant management time or resources to such a project. An expansion that did not reduce their costs is not one they would have any incentive to pursue.

This is particularly a problem for the pipeline, as opposed to the liquefaction plant. While there are issues to resolve in pursuing an expansion of the liquefaction plant (e.g. how to pay for shared costs), in general, expansion of a liquefaction plant is straightforward: with enough gas, a company can add another train with its own ownership and structure. By contrast, all the gas will be transported through the same pipeline, making the question of the participants' interest in expansion critical.

It will thus be essential to have a strong, pro-expansion partner in pipeline component of the project. If the state were to carry its own interest in the GTP and pipeline, it could play this role itself. However, this may place a significant burden on the state that it is not best positioned to carry. If the state does not wish to be the primary driving force behind future expansions to the GTP and pipeline, or does not believe it has the capabilities to play such a role, there may be a significant benefit to the involvement in the project of an experienced third-party pipeline company. Unlike the producers, such companies make their money from moving gas, not selling it and so they have an overwhelming interest in expansions.

The MOU offers a clean break from AGIA and avoids any contentious dissolution that could create uncertainty for the midstream portion of the AK LNG project

Transitioning from AGIA to a commercial relationship. In proceeding with the AK LNG project, the state must also consider how it concludes its obligations under the Alaska Gasline Inducement Act (AGIA). The potential liability to the state in terminating the AGIA license is unclear. The best case would involve a determination that the project proposed under AGIA was uneconomic; however if such a determination were not mutual, it could lead to protracted arbitration between the parties. The worst case scenario might involve the application of the 'licensed project assurances' section of AGIA, which provides for a payment of three times total expenditures to the date to the licensee, in the event that the state provides preferential treatment to an alternative project.

Whatever the potential outcome, there is a clear interest in terminating the AGIA relationship cleanly and painlessly; the alternative is to expose a core component of the project to doubt and delay as these issues are resolved. A key benefit of the MOU would appear to be that, when translated into action, it will lead to the dissolution of the AGIA license by mutual consent without penalty, and to the state's ability to leverage the work undertaken so far under the license.

There are, however, also potential costs to the proposed involvement of TC in the project—and the state ought to weigh these carefully.

The tariff agreed for the pipeline appears competitive, but the state will never know if this is the best deal without going to a bid; a bid, however, is also no guarantee of a better deal

Tariff for pipeline. The tariff structure proposed under the MOU appears to be solidly competitive when compared to tariffs for interstate pipelines regulated by the Federal Energy Regulatory Commission (FERC). **In particular, the ratio of debt to equity proposed for the project (75:25 for the initial project, and 70:30 for subsequent expansions) serves to create a competitive rate-setting WACC for the initial project of below 7%.** This places some financing risk on TC, and appears to be a component of the proposed terms that should be attractive to the state. The 'rate tracker' component of the MOU however, also places some risk on the state; if the 30-year Treasury rate rises significantly between now and the time of Final Investment Decision (FID), the rate-setting WACC will correspondingly increase.

Without opening the process to competitive bidding, it will never be possible to know whether the state could achieve more advantageous tariff terms. By opening the process to competitive bidding, however, the state would likely lose the benefits of a painless exit from the AGIA license, and it is possible the state may not get better or even equivalent terms to those on offer through the MOU. Given the uncertainty that surrounds such contingencies, how these costs and benefits are weighed are a matter for individual judgement as well as sound legal advice.

Flexibility. The second important question to consider is that of the benefit of maintaining flexibility in the project structure at this early point in the definition of the project. Since one of the key benefits for the state from the arrangement stems from its ability to help the state better manage its capital constraints, **it is important to maintain flexibility in the level of ownership and control over the GTP and pipeline that the state divests until such a time as its true capital constraints are better known.** The equity option provided by the MOU, under which the state can reclaim up to 40% of its initial interest in the GTP and pipeline by repaying TC costs incurred to date plus 7.1% interest would appear to be an attractive component of the proposal.

Termination clauses. Given the potential for movement in the tariff due to the 'rate-tracker', however, as well as the many unknowns around the state's true capital constraints, it may be desirable to maintain an ability to fully exit from the arrangement should circumstances warrant it, before FID is taken. In this regard, the MOU offers some important benefits, but also some restrictions.

The MOU offers several off-ramps for the relationship to be terminated—but in most cases, the state would have to reimburse TransCanada for its development expenses

On the one hand, it provides strong and clear termination options for the state—the state may terminate with 90 days notice for any reason prior to the commencement of Front End Engineering and Design (FEED), and for any reason at the time of FID. In order to terminate, the state need only repay TC development costs incurred, with 7.1% interest. By itself, this appears attractive.

However, if the state continues with the project as an equity participant, or continues with a substantially similar project, it is obligated to provide TC an option to participate on terms consistent with the MOU, but with the return on debt and equity used in setting the tariff "to be negotiated based on conditions existing at the time." It is possible the state may at some point have other, more advantageous partnership options, or might find it has sufficient capital flexibility as to be able to benefit from its lower cost of capital by carrying the full pipeline and GTP share itself. Sound legal advice should be sought to understand how much flexibility the termination arrangements under the MOU provide to the state in such circumstances, how much such changed circumstances could define the terms offered to TC for participation at such time, and the basis on which it might be possible for the state to conclude that TC was not able to offer competitive terms, and proceed without TC, were that to be in the state's interest.

Risk-sharing. The final important question is that of the appropriate commercial sharing of risk and reward under the MOU. Both the state and TC have the ability to terminate the agreement for a range of reasons; the state might seek to terminate if it does not wish to proceed with the project, for instance, while TC may seek to terminate if it is unable to arrange a financing structure for the project compatible with its tariff commitments. **In all instances, however, it appears that the state would repay TC its development costs to date with interest. The commercial risk borne by TC in this arrangement thus appears to be quite limited; the appropriateness of this is another cost that must be weighed in considering the substantial benefits offered by the arrangement.**

WHAT ARE THE FINANCIAL BENEFITS TO THE STATE FROM AK LNG?

A project of this magnitude stands to bring several benefits to Alaskans, including jobs during construction and thereafter as well as delivering cheaper energy to Alaskans relative to fuel oil and/or diesel. There are two direct financial benefits.

Depending on how the state participates in AK LNG, its revenues could rise by $2.9 to $4 billion a year

More revenues for the treasury. LNG projects are attractive because they require a large-scale cash commitment upfront but then deliver long-term revenues for an extended period of time (as Kenai LNG has done since 1969). As such, private companies and governments like LNG projects because they can count on revenues from LNG to finance other commitments they have. In any given year, the state's revenues will depend on a number of factors such as:

- The price at which the LNG is sold
- The operational reliability of the project (is it running at full utilization or not?)
- The amount of debt that the state has outstanding
- Operational and maintenance expenses
- The precise ownership structure at each revenue-generating point

Our baseline scenarios show that the State of Alaska could generate $2.9 to $4 billion annually for a 20+ year period. Of course, there are cases where this number will be lower (as we explore on the section regarding risk) but there will also be times when this number will be higher.

The creation of a large diameter line will open the door for additional gas development on the North Slope

Development of additional resources on the North Slope. Without a way to bring gas to the market, there is no incentive for any private company to explore for natural gas since the gas will be stranded. The United States Geological Survey (USGS) estimates that the North Slope could hold over 200 trillion cubic feet (tcf) of gas (by comparison, the gas at Prudhoe Bay and Point Thomson is estimated at 35 tcf). **A large-scale pipeline, together with an LNG export facility at Nikiski, provide an outlet that will reassure companies of a way to monetize any discoveries they make, thus delivering additional long-term revenues from royalties and a production tax from new developments.**

WHAT ARE THE RISKS FOR ALASKA?

A project of this magnitude entails several risks, and Alaska's exposure will depend on the way that the state participates in the project. Broadly speaking, however, **the project faces two risks (a) that it will not move forward or (b) that it will not generate as much money as expected.**

If the project does not move forward, the state will have lost the money it spent in studying and advancing the project

AK LNG a 'no-go'. The first risk is that the project may not be authorized by its sponsors (which would include the state) because the sponsors do not think the project is a good investment relative to their alternative opportunities. In this case, the state, just like the other investors, would have spent money on an endeavor that is stalled. How much money might the state put into the effort?

The answer depends on when the project becomes stalled. Since LNG involves a large capital commitment, investors take a long time to study and mitigate risks as much as possible before authorizing the investment, and typically **less than 10% of the project cost is spent before authorization, known as Final Investment Decision (FID)**. The more advanced the planning becomes, the more money is expended on the project, but, naturally, the sponsors only authorize more money if they remain confident that the project can succeed. There is, therefore, a check—the more money that is spent on the project, the greater the evidence that the sponsors think it will succeed.

In our estimate, **the state could spend up to $100 million during the first planning phase called pre-FEED (Front End Engineering and Design) and up to $500 million during the FEED phase**. This amount is set by the state's ownership share of the project, and it is matched by spending by the producers, which own 75% of the project, and TransCanada, which will own a portion of the gas treatment plant and pipeline.

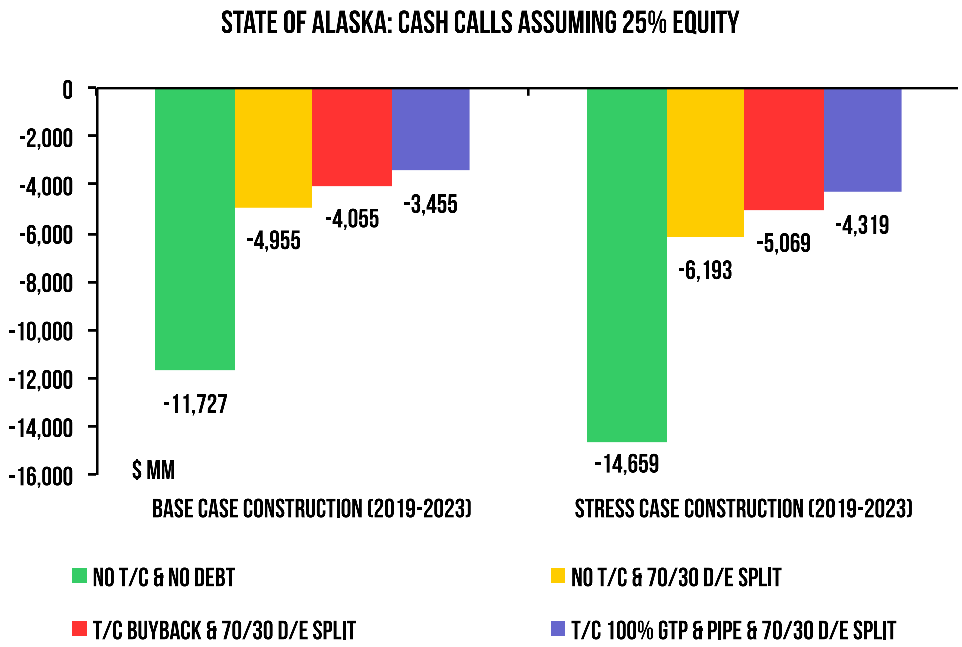
It is only if all the sponsors agree that the results of these studies are positive that a move to FID will be made. As such, **the state's loss in the case of a 'no-go' could be $600 million, at least based on today's understanding of what these studies are expected to cost.**

LNG projects are subject to frequent delays and cost overruns—the state should understand that these risks exist

Cost-overruns. As an investor in the project, Alaska would have to cover the costs of the project that correspond to its share. LNG projects, however, are complicated and subject to delays and overruns. At this stage, **the project has an announced cost of anywhere from $45 billion to $65 billion, evidence of the considerable uncertainty that exists right now about the project.** As the project moves to FID, the range will narrow down considerably, and all the sponsors will have a much clearer picture of what the project is expected to cost.

Even so, delays and overruns happen: **enalytica's survey of cost-overruns in a sample of sixteen LNG projects over the last decade showed an average cost overrun of 25%, although the number ranged from 0% (on budget) to 120% (more than double the cost).**

Therefore, the state should understand exactly how cost overruns will affect its capital commitments during the construction phase of the project, where most of the capital is expected to be spent.



In our baseline scenario, the state's cash outlays during construction are estimated at $11.7 billion assuming that the state has a 25% equity in the project, takes on no debt to finance its share of the spending, and does not include TransCanada as a partner in the GTP and pipeline (and thus is responsible for 25% of all the infrastructure costs). **A 25% cost escalation would push the state's cash call during construction to $14.7 billion (assuming on debt).**

If, however, the state borrowed to cover up to 70% of its share (a 70-30 debt-equity structure), **the state's cash calls would be $5 billion in the baseline and $6.2 billion in the stress case. Bringing TransCanada as a partner would lower the state's cash call during construction further to $4 billion (equity buyback) or $3.5 billion (no equity buyback). In a stress case, these numbers increase to $5.1 billion and $4.3 billion, respectively** (stress case assumptions can be found on the following page).

Lower revenues during operations. Like any business, the project's revenues will depend on market conditions—and in particular on the amount of LNG begin sold and the price at which it is being sold.

LNG projects are high-reliability assets that tend to operate at or very close to their design capacity—over the last decade, average percentage utilization has been at the high 80s. **But in any given year, operational problems, weather, or other accidents can reduce output, which in turn, will reduce revenues.** In an even worse case, if the state has committed to sell LNG to a buyer, reduced output might force it to procure LNG in the open market from third parties in order to honor its contractual commitments.

Price is the other risk facing the project, but this risk is quite different from price risk for oil. In oil markets, prices fluctuate from day to day, and this fluctuation applies to all buyers and sellers at the same time. LNG operates in a similar way but with a twist: project sponsors typically pre-sell their LNG under long-term contracts (15 to 20 years) in order to have assurances that there will be demand for their product before authorizing construction (FID). **The sales contracts set out a price mechanism, and while the final price may fluctuate based on market conditions, the precise manner of the fluctuation will be contract-specific and will not be affected by other contracts.**

For example, assume that Alaska LNG signed a long-term contract with a price mechanism whereby every $1/bbl increase in the price of ANS oil raised the LNG price by ¢13 per million British Thermal Units (mmbtu) (a typical relationship for today's market). If another project sold LNG to the same buyer at a lower rate (say ¢12/mmbtu for each $1/bbl in ANS), that new price would have no impact on Alaska's sales price.

Therefore, **price risk in long-term contracts takes two forms: a change in the price of the underlying commodity to which the LNG is linked (in Alaska's case, likely crude oil) or a deep and unexpected change in market fundamentals that leads either party to request a price renegotiation.** These price renegotiations are standard in LNG contracts to make sure that the sales agreement can survive the natural changes that occur over a 20 or even 30 year period—even so, most LNG contracts formally define the conditions that are required for a renegotiations and, potentially, even limit its scope (for example, limiting any price changes to a set percentage).

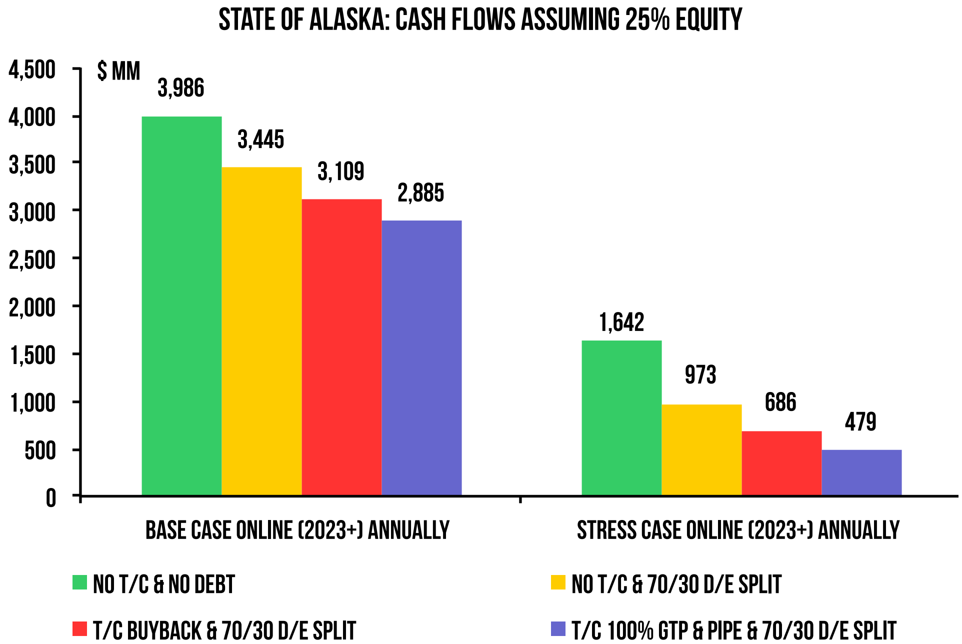
To quantify these risks, **we have developed a "stress case"** that estimates the financial implications of three combined risks:

- Higher capital costs by 25% (versus a baseline of $49 billion), shown above
- Lower sales price at $7/mmbtu versus the baseline of $15/mmbtu
- Utilization at 80% rather than 100%

Combined, these effects will increase the state's cash outlays during construction (shown above) and lower the state's cash receipts during the operational phase (due to lower volumes, prices and higher debt service as result of the additional debt taken on to cover construction costs).

In a stress case scenario the state would likely suffer from a suboptimal return rather than a negative cash flow

In the baseline scenario, the state's revenues range from $2.9 to $3.9 billion annually depending on whether the state takes on debt and whether TransCanada is part of the project. **In the stress case, cash inflows range from $479 million to $1,642 million due to higher debt service and lower revenues from lower prices and less volumes sold.**



This analysis underscores a crucial point: an adverse shock for an LNG project usually means that the project will not generate as much money as anticipated, and it can also perhaps prove to be an uneconomic investment (not earning the return to investment expected). **But LNG projects rarely turn cash negative, especially for extended periods of time—the risk is a sub-optimal return.**

HOW COULD THE STATE MINIMIZE ITS RISKS?

Risk mitigation is an essential success strategy for LNG projects. There are several options for the State of Alaska to adjust its risk exposure to the LNG project.

Third-party financing, including from the official sector, is a well established risk mitigator

Third-party finance. External finance is well established in LNG; financiers include:

- The parent companies of the project sponsors
- Consortia of commercial banks
- Official banks and/or export credit agencies (such as the US Export-Import Bank, the Nippon Export and Investment Insurance from Japan or the Japan Bank of International Cooperation),
- Multilateral banks (Inter-American Development Bank) and commercial banks

In recent years, the amount secured by third party finance has been significant; IHS, for example, estimates that LNG projects have secured over $97 billion in third-party financing since 2000, and **several projects have raised billions in dollars in third-party financing** (see table below for details).

EXAMPLES OF EXTERNAL FINANCE IN RECENT LNG PROJECTS

PROJECT	AMOUNT	SOURCES
AP LNG (AUSTRALIA)	$5.8 BILLION	US EXIM, CHINA EXIM, BANKS
ICHTHYS LNG (AUSTRALIA)	$20 BILLION	JBIC, KOREA AND AUSTRALIA EXIM, BANKS, SPONSORS
PAPUA NEW GUINEA LNG	$14 BILLION	SIX ECAS AND 17 BANKS, EXXONMOBIL
PERU LNG	$2.25 BILLION	IADB, US EXIM, KOREA EXIM, IFC, OTHERS
SAKHALIN-2 (RUSSIA)	$6.4 BILLION	JBIC, NEXI, BANKS
TANGGUH LNG (INDONESIA)	$3.5 BILLION	JBIC, ADB, BANKS

Many projects are financed through non-recourse debt, where the equity owners are not liable for the debts of the project

A particularly popular form of third-party financing includes the use of **non-recourse debt: in this case, the borrower offers the future revenues from a project as a guarantee for the loan, and the lender has no recourse to the owner of the project if the project fails to generate sufficient cash to pay for the loan.** This option can be used to minimize the balance sheet exposure of any one project by creating a separate vehicle to handle both the revenues as well as the debt of the project.

Selling down equity. While the HOA and MOU envision that the State of Alaska is likely to have 20-25% equity in the liquefaction project and 0-10% equity in the gas treatment plant and pipeline, **the state can adjust its share over time. This is standard practice in LNG, and most LNG projects start operations with a different ownership structure than when they were conceived.**

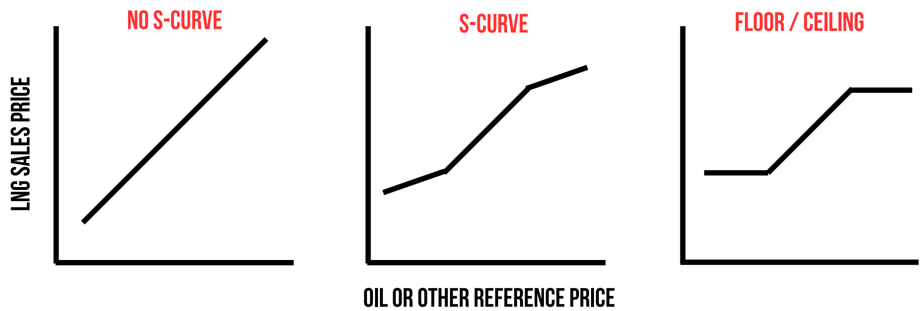
Just because the state might start out with 25% equity, it does not have to hold that equity—it can sell down as time goes by

In particular, LNG buyers who sign-up for long-term contracts are often interested in purchasing equity in the LNG projects that supply them with gas. They do this as a means to generate additional revenue, as a way to hedge against higher sales prices and as a way to boost their own sense of supply security (by virtue of buying gas from one of "their" projects). **Enalytica estimates that in 50% of the LNG capacity in the world today, the output is sold contractually to a company that is a part-owner of the liquefaction facility,**

and in 20% of the world's LNG capacity all the output is sold to project partners.

More importantly, as the project moves ahead, the equity has more value in the same way that a fully planned and permitted real estate development that has begun construction will sell for more than an empty, undeveloped block of land. As such, **the longer the State of Alaska holds on to its equity stake, the greater the value it could get should it choose to sell it.**

Price protection. The state's price exposure to LNG will be defined in the sales contracts that is signs, and will thus be known and understood at the time that the state is asked to sign off on FID. In itself, this fact is a source of reassurance and protection. But there are other measures that the state could employ to protect against volatility or low prices. Several LNG contracts contain "S-curves," which smoothen the volatility of the LNG price based on changes in the oil price.



S-curves can protect the state's sales price in a downside world while forgoing some of the upside of high prices

The schematic above explains how S-curves work. In a typical contract without an S-curve, the LNG price will rise and fall according to the benchmark price (in Asia, crude oil)—this is the example shown on the far left. But it is also possible to employ **a S-curve relationship, whereby, after certain thresholds, the price of LNG falls or rises more slowly (middle chart). In extreme cases, the S-curve can turn into a ceiling and floor price for the LNG.**

Such a measure can be especially useful for projects like AK LNG which are particularly expensive and which might, therefore, be interested in ensuring a certain "minimum" return. **In exchange for securing a floor price, however, the seller must give some of the upside (ceiling).**

Partnership. The State of Alaska has one other risk mitigator—its partnership with ExxonMobil, BP, ConocoPhillips and TransCanada. When the time comes to decide whether the project should move forward—and thus authorize spending in the tens of billions of dollars—**the state will not be making this decision alone but together with some of the largest and most experienced LNG players in the world who will be risking their own shareholders' money in this project.**

While this is no guarantee against the state making a sub-optimal decision, it does provide some reassurance that the state will only invest money if the project passes the stringent criteria that ExxonMobil, BP, ConocoPhillips and TransCanada impose for their investments.

GLOSSARY

Acronyms:

AGIA - Alaska Gasline Inducement Act

FEED - Front End Engineering Design

FERC - Federal Energy Regulatory Commission

FID - Final Investment Decision

GTL - Gas-to-Liquids

GTP - Gas Treatment Plant

HOA - Heads of Agreement

LNG - Liquified Natural Gas

MOU - Memorandum of Understanding

pre-FEED - pre-Front End Engineering Design

SPA - Sales and Purchase Agreement

WACC - weighted average cost of capital

Units and conversions:

abbreviation	unit	relevant conversions
bbl **boe**	barrel (oil) barrel of oil equivalent	1bbl = 1 boe = 6000 cubic feet (6 mcf)
$/bbl	dollars per barrel (oil)	$6/bbl = $1/mcf ≃ $1/mmbtu
btu **mmbtu**	British thermal unit million British thermal units	$1/mmbtu ≃ $1/mcf (varies based on heat content of gas)
mmcf/d	million cubic feet per day	1,000 mmcf/d = 7.8 mmtpa = 10.3 bcm/yr
bcf **tcf**	billion cubic feet trillion cubic feet	1 tcf = 28.32 bcm = 20.67 million metric tons LNG
bcf/d	billion cubic feet per day	1 bcf/d = 7.8 mmtpa = 10.3 bcm/yr
bcm	billion cubic meters	1bcm/yr = 0.73 mmtpa = 96.7 mmcf/d
mmtpa	million metric tons per annum (LNG)	1mmtpa = 1.37 bcm = 48.37 bcf/y = 132 mmcf/d
mmtoe	million metric tons of oil equivalent	1 mmtoe = 1.11 bcm = 39.2 bcf = 107.4 mmcf/d

ABOUT US

Janak Mayer. Before co-founding enalytica, Janak led the Upstream Analytics team at PFC Energy, focusing on fiscal terms analysis and project economic and financial evaluation, data management and data visualization.

Janak has modeled upstream fiscal terms in all of the world's major hydrocarbon regions, and has built economic and financial models to value prospective acquisition targets and develop strategic portfolio options for a wide range of international and national oil company clients. He has advised Alaska State Legislature for multiple years on reform of oil and gas taxation, providing many hours of expert testimony to Alaska's Senate and House Finance and Resources Committees.

Prior to his work as an energy consultant, Janak advised major minerals industry clients on a range of controversial environmental and social risk issues, from uranium mining through to human rights and climate change. He has advised bankers at Citigroup and policy-makers at the US Treasury Department on the management and mitigation of environmental and social impacts in major projects around the world, and has undertaken macroeconomic research with senior development economists at the World Bank and the Peterson Institute for International Economics.

Janak holds a BA with first-class honors from the University of Adelaide, Australia and an MA with distinction in international relations and economics from the Johns Hopkins School of Advanced International Studies (SAIS).

Nikos Tsafos. Nikos Tsafos has a diverse background in the private, public and non-profit sectors. He is currently a founding partner at enalytica. He previously spent 7 ½ years at PFC Energy, where he advised the world's largest oil and gas companies on some of their most complex and challenging projects; he also played a pivotal role in turning the firm into one of the top natural gas consultancies in the world, with responsibilities that included product design, business development, consulting oversight and research direction.

Prior to PFC Energy, Nikos was at the Center for Strategic and International Studies (CSIS) in Washington, DC where he covered political, economic, and military issues in the Gulf, focused on oil wealth, regime stability and foreign affairs. Before CSIS, he was in the Greek Air Force, and prior to his military service, Nikos worked on channeling investment from Greek ship-owners to Chinese shipyards.

Nikos has also written extensively on the domestic and international dimensions of the Greek debt crisis. His blog (Greek Default Watch) was listed as one of "Europe's Top Economic Blogs" by the Social Europe Journal, and his book "Beyond Debt: The Greek Crisis in Context" was published in March 2013.

Nikos holds a BA with distinction in international relations and economics from Boston University and an MA with distinction in international relations from the Johns Hopkins School of Advanced International Studies (SAIS).

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