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Evaluation of SB 138 & Associated Proposed North Slope Natural Gas Commercialization Proposals

Presentation to House Resources

Roger Marks

March 27, 2014

Roger Marks - Background

- **Since 2008**: Private consulting practice in Anchorage specializing in petroleum economics and taxation
  - Clients include: State of Alaska Legislature, federal government, local municipalities, University of Alaska, independent oil and gas explorer/producers, pipeline companies, investment firms
- **1983-2008**: Senior petroleum economist with State of Alaska Department of Revenue Tax Division
  - Fiscal development
    - Statutory and regulatory design
    - Petroleum economic and commercial valuation of exploration, development, production, transportation, refining, marketing, taxation
    - Analysis of international competitiveness
    - Oil and gas valuation
  - North Slope gas commercialization
    - Economic valuation
    - International competitiveness
    - Pipeline financing
    - Taxation
    - Tariff design
- **1977-1983**: Petroleum economist with United States Geological Survey
  - Resource evaluation of unleased acreage on Alaska federal Outer Continental Shelf
  - Design of bidding systems
- **Publications on Alaska petroleum taxation**: Journal of Petroleum Technology, OPEC Review, Journal of Energy Finance and Development, Oil & Gas Financial Journal, Journal of Economic Issues, Journal of Legal Issues and Cases in Business

Outline

- 1. Introduction: Market and Timing Landscape
- 2. High-level Decisions
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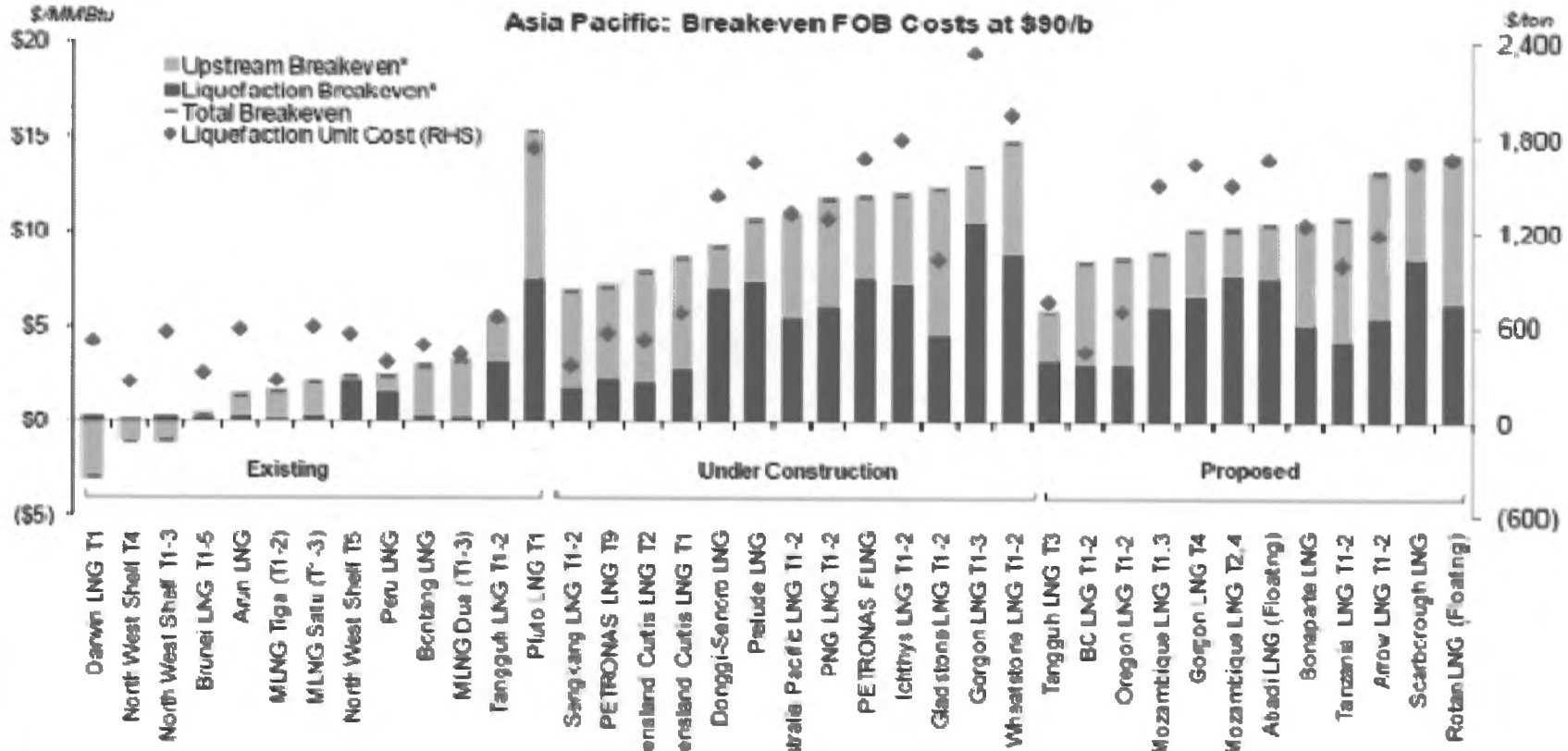
  - B. Regulation
  - C. Ownership (and Partnerships)
- 3. Role of AGIA in Proposal
- 4. Taxation

1. Introduction: Market Challenges

- Competition
  - Twice the amount of supply as there is demand in Asia in 2030
- Pricing
  - Prices appear to be falling
  - Compete based on cost
- Size Burden
  - Need to capture large incremental share of market in short amount of time
  - Higher breakeven price than much of the competition

New LNG Projects are Expensive



PFC Energy

Timing Landscape

- Momentum in temporal context
  - Emphasis on present value diminishes the value of future events
  - Issue is not present value but value to future generations
- Options: A modified deal starting a little later could create more long-term benefits to state
  - Higher revenues
  - Lower priced gas to Alaskans
  - Less risk

HOW PRESENT VALUE IS CALCULATED

	Year	Discount Factor @ 7%	Nominal Amount	Discounted Amount
Today / Pre-FEED	2014	1.00	1,000,000	1,000,000
	2015	0.93	1,000,000	934,579
FEED	2016	0.87	1,000,000	873,439
	2017	0.82	1,000,000	816,298
	2018	0.76	1,000,000	762,895
FID / Construction Starts	2019	0.71	1,000,000	712,986
	2020	0.67	1,000,000	666,342
	2021	0.62	1,000,000	622,750
	2022	0.58	1,000,000	582,009
	2023	0.54	1,000,000	543,934
Gas Starts Flowing	2024	0.51	1,000,000	508,349
	2025	0.48	1,000,000	475,093
	2026	0.44	1,000,000	444,012
	2027	0.41	1,000,000	414,964
	2028	0.39	1,000,000	387,817
	2029	0.36	1,000,000	362,446
	2030	0.34	1,000,000	338,735
	2031	0.32	1,000,000	316,574
	2032	0.30	1,000,000	295,864
	2033	0.28	1,000,000	276,508
	2034	0.26	1,000,000	258,419
	2035	0.24	1,000,000	241,513
	2036	0.23	1,000,000	225,713
	2037	0.21	1,000,000	210,947
	2038	0.20	1,000,000	197,147
	2039	0.18	1,000,000	184,249
	2040	0.17	1,000,000	172,195
	2041	0.16	1,000,000	160,930
	2042	0.15	1,000,000	150,402
	2043	0.14	1,000,000	140,563
	2044	0.13	1,000,000	131,367
	2045	0.12	1,000,000	122,773
	2046	0.11	1,000,000	114,741
	2047	0.11	1,000,000	107,235
	2048	0.10	1,000,000	100,219
			PRESENT VALUE	**13,854,009**

2. High Level Decisions under Proposal

- State takes its production taxes and royalties as in-kind gas
- Tariffs and expansions will not be regulated
- TransCanada (and perhaps SOA as partner) will own share of GTP and pipeline, and SOA will own share of LNG facilities, commensurate with state's share of gas (about 25%)
- Designed to amicably transition out of AGIA

A. In-Kind Gas

- Taking taxes and royalties as in-kind gas helps out the economics of the project considerably
- The state does not need to own the pipeline to take the gas in-kind
- Marketing the gas
  - By taking gas in-value the state benefits from some of the best marketers in the world
  - May want to consider linking in-kind provision with agreement by producers to market state's gas with their gas at the same price they get

The Long-Term Liability of Firm Transportation Agreements

- If the state takes its royalties and taxes in value:
  - Producers pay to state an amount of money equal to that percentage of the gas
  - The producers pay for that capacity
  - Slowly get it back over time through tariff deduction
- Once it is constructed it cannot be cancelled
  - If the pipeline is hopelessly costly, or unsuitable, or the market crashes, or reserves run out, that is not the state's problem
- When the state takes its taxes and royalties as in-kind gas, the state will take on the long-term firm transportation liability
  - Ship or pay commitment
  - A long-term liability for capacity
  - An asset to the owner

B. Regulation

- Proposal under HOA is for FERC to regulate under Section 3 of the Natural Gas Act
  - Mainly designed for licensing the siting, construction, expansion, and operation of LNG import or export terminals
  - Terminals include facilities used to transport or process gas
  - Rarely used to include a large pipeline with local consumption
- No regulation of tariffs or expansions
  - To get reasonable tariffs and expansions, state ownership necessary
  - Unclear what happens as in-state needs expand:
- Precedent for RCA to regulate in-state and export pipeline and gas treatment under AS 42.08
  - Regulation is the trade-off for privilege of natural monopoly
    - May enhance market efficiencies to have a transparent pipeline cost

Example

Initial Gas Disposition (billion cubic feet per day)	
Total Gas	2.4 bcf/d
State Share	25%
State Gas	0.6 bcf/d
To Fairbanks	(0.05 bcf/d)
State Gas to Asia	0.55 bcf/d

Ownership and Partnership

- Need for ownership due to no regulation on tariffs and expansion, and for lower tariffs
- State may or may not need partner for expertise assistance
  - Producer expertise
  - AGDC expertise
  - TransCanada's expertise in gas treatment unclear
  - To the extent the need for expertise is discounted, and the state needs a cash partner, it does not necessarily need a pipeline company partner, but a general investment partner

State May or May Not Need Partner for Cash or Lower Tariffs: 2011 Citigroup AGDC Financing Plan

- Possibility of 100% debt financing
  - Combination of revenue bonds and state backing
  - Appears to be less risky than ASAP plan
  - Possibility of deferring most cash outflows until gas starts flowing
  - May have short-term impact on credit rating that would reverse once gas revenues start coming in
- Possibility of tax-exempt bonds through Alaska Railroad
  - Directed at industrial development projects
  - Requires IRS private letter ruling
  - Reduces cost of debt about 25% relative to taxable debt
- Would require potentially no or little equity (cash) before gas starts flowing

Debt Capacity, Firm Transportation Commitments, and In-Kind Gas

- When the state takes its taxes and royalties as in-kind gas, the state will take on a long-term firm transportation liability to TransCanada
- It has been suggested that there are limits on how much the state can finance to own the whole 25% because of limits on its debt capacity.
- If the state is taking its taxes and royalties in kind, any part of the project the state does not own it will have to make a firm transportation commitment on. This commitment is a long-term liability; i.e., debt.
- That debt should have no different impact on the state's debt capacity than debt used to finance ownership.
- If limit on state debt capacity is an issue, this would preclude the state from taking the taxes and royalties in kind.

Ownership: Risk of Failure to Sanction

- Sponsors could spend over $2 billion to get to FID and have a project not materialize, of which SOA would be responsible for 25%, regardless of whether it exercised ownership option with TransCanada
- Are producers better equipped to handle that risk?
  - Diversification – some of their other prospects will get sanctioned
  - Finite capital competing not only for gas, but for oil
  - Where other countries do share this risk, the takes are higher
- Will this money make a material difference to the viability of the project? Balance:

How near tipping point	Probability of Project
Size of the prize	How material is $600 mm

- Could pursue arrangement with producers to buy in to project once it is sanctioned (or at least after pre-FEED) and re-pay feasibility costs with interest

3. Role of AGIA in Proposal

- Public comments by administration:
  - Aggressive time frame to get gas to market
  - Desire to avoid potential lengthy and costly legal fight over ending AGIA license
  - Proposal designed to end AGIA license amicably
- License project assurances (treble damages) clause in AGIA
- Appears plan was crafted (at least in part) around giving TransCanada a material role to avoid potential AGIA liabilities
- Could there be better terms if state was not so constrained by AGIA?

Areas Where State Could Possibly Have Better Terms If It Had No Partner or a Different Partner

- <u>If No Partner</u>
  - Possibility of full ownership of 25% share of GTP/Pipe with 100% debt financing and possible tax-exempt debt
  - Lower cost of capital: higher gas revenues/lower cost gas to consumers
  - There is a misalignment of interests between shippers and non-shipper partners
- <u>If Had Different Partner (or could renegotiate MOU)</u>
  1) Sharing failure to sanction risk
  2) Share in benefit of lower interest rates
  3) Better cost of capital terms in tariff
  4) Higher ownership share than 40% (of 25%)
  5) Extended time frame to make decision on exercising 40% (of 25%) ownership option
  6) Remove option of TransCanada to terminate after pre-FEED

Role of Financing Terms in Tariffs

- Financing costs a significant part of tariff
- Cost of capital:

(Pct debt X Cost of Debt) + (Pct equity X Cost of Equity)

- Will determine gas revenues and price of gas to Alaskan consumers

Are Better Cost of Capital Terms Possible

- Terms on existing pipelines may not be relevant
  - May not need pipeline company for investment partner
  - 75% of the pipeline is being built by well financed, well capitalized and experienced major international oil corporations
- Bidder could come in needing lower returns
- May be trade-off between risk sharing and returns

How Bound is State by AGIA

- License Project (Treble Damages) Clause (AS 43.90.440):

  "If ... the state extends to another person **preferential** royalty or tax treatment or **grant of state money** for the purpose of facilitating the construction of a competing natural gas pipeline project in this state ... the licensee is entitled to payment from the state of an amount equal to three times the **total amount** of the expenditures incurred and paid by the licensee ... "

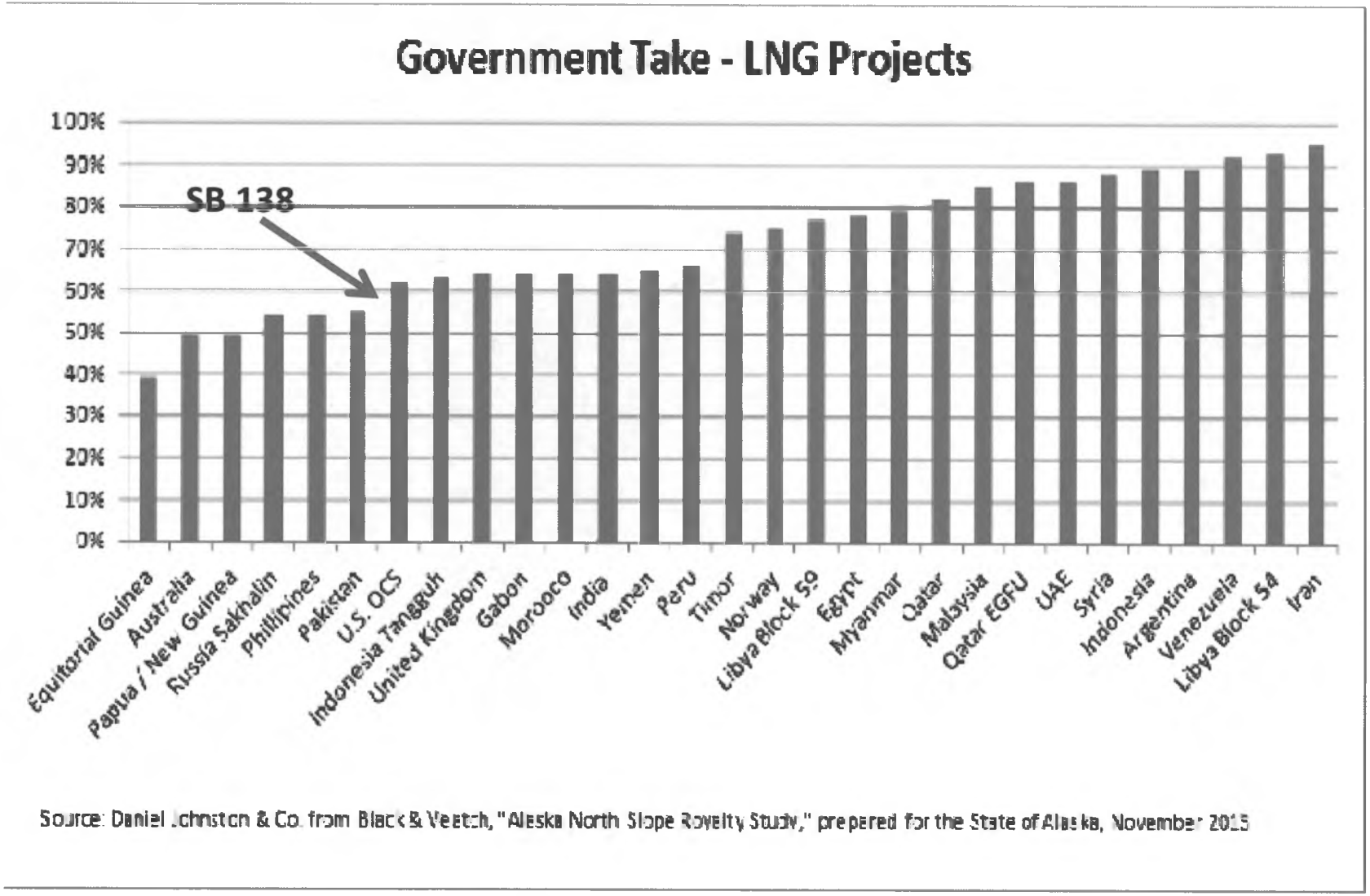
- Ambiguities
  - "Total amount"
  - "Preferential"
  - "Grant of state money"

Options

- Assess legal exposure
- Engage TransCanada
- Renegotiate
- Settlement
- Litigation

4. Taxation: Production Tax

- Taking taxes in-kind enhances the project economics to the sponsors
  - It makes sense to assess an in-kind tax on gross
- Appropriate rate: fair share is what you can get in a competitive environment (jurisdictions with similar risk/reward structure)



Source: Daniel Johnston & Co. from Black & Veatch, "Alaska North Slope Royalty Study," prepared for the State of Alaska, November 2015

Property Tax

- Property tax based on value is regressive: the higher the cost the higher the tax
  - Adds to economic risk
- Plethora of litigation on valuation
- There are certainly social impacts from development that need to be addressed and paid for
  - It is not clear that impacts are directly related to value
- HOA: look at cents/mcf tax plus impact payments

Fiscal Stability

- Producers have continually expressed necessity
- Some fiscal stability may be necessary
- SB 138 not stable
- Scope out producers intentions as to what constitutes adequate stability

Evaluation of SB 138 (HB 277) and Associated Proposed North Slope Natural Gas Commercial Arrangements

Roger Marks
Prepared for the Senate Finance Committee
February 18, 2014

I. Introduction

This report is an evaluation of SB 138 (also HB 277) and associated proposed commercial instruments related to the commercialization of North Slope gas. These other instruments include the Heads of Agreement (HOA) between the state, TransCanada, ConocoPhillips, BP, and ExxonMobil, and the Memorandum of Understanding (MOU) between the state and TransCanada. In addition, the role of the Alaska Gasline Inducement Act (AGIA) in these proposals will be discussed. "State" includes DNR, DOR, and the Alaska Gasline Development Corporation (AGDC).

The plan put forward by the administration is thoughtful and could be useful in moving a large scale North Slope natural gas commercialization project forward. This report contains observations about the plan, and offers some alternative options the legislature may want to consider.

This analysis is based on examination of public documents.

Two high level observations may be useful in deciding how to proceed on these issues: first regarding the outlook for the project's viability, and second, the timing.

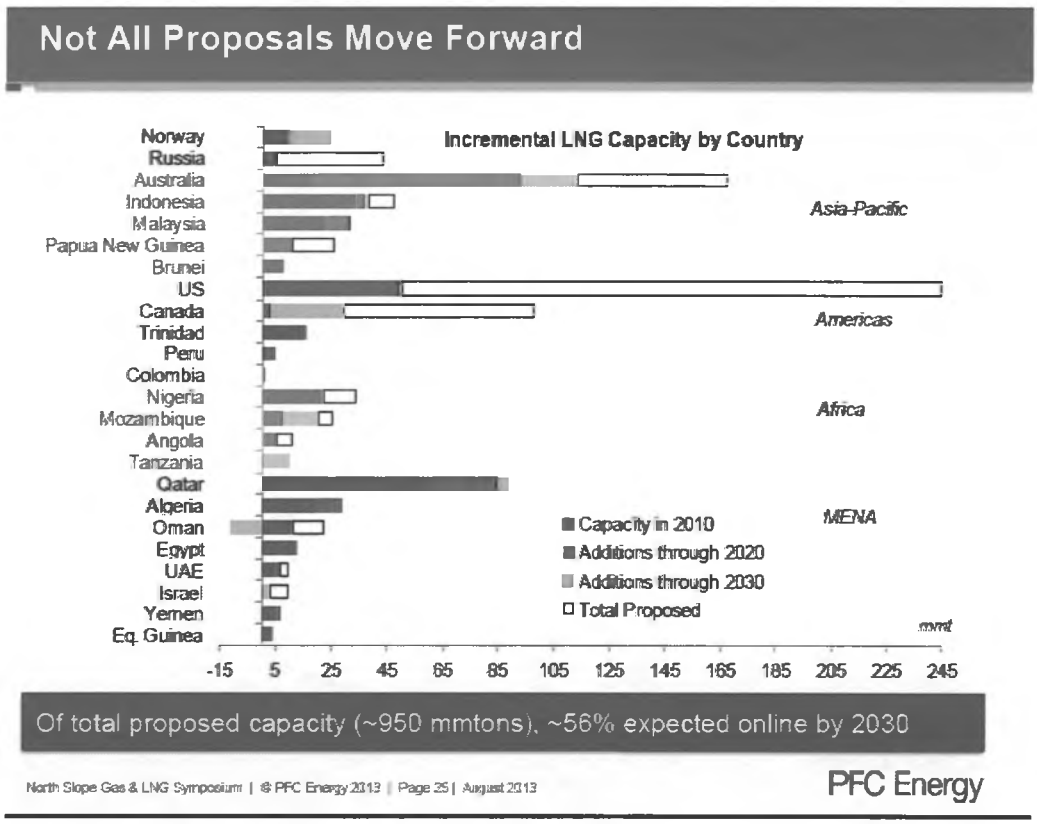
The economics of a large scale natural gas export project are challenging, and it is far from certain that the project will happen.

Expected LNG demand growth is encouraging, but the competition is considerable. Currently 19 nations actively export LNG and many are eyeing the Asian market. An additional one has a plant under construction, and four more are in various stages of feasibility studies. There will be nearly twice as much supply chasing the Asian market as there will be demand in 2030. (See Figure 1)

At the same time LNG prices in Asia may be falling. Prices have been linked to oil, but the link appears to be either softening or decoupling. Asian buyers realize that due to skyrocketing oil prices, suppliers were making a windfall. With the intense competition, buyers will be able to leverage lower prices based on actual costs, and sellers will have to compete based on cost.

While average prices in Asia currently may be high (approximately $14-$18 per million BTUs [mmbtu]), they reflect the high volumes of gas subject to older, higher-priced contracts linked to oil prices. Newer contracts in China average around $11-$12/mmbtu. Russia will be selling some

FIGURE 1



gas for as low as $6/mmbtu, and Yemen at $8/mmbtu.[1] Cheniere Energy, Inc. will be selling Gulf of Mexico LNG to Asia based on Henry Hub prices.[2]

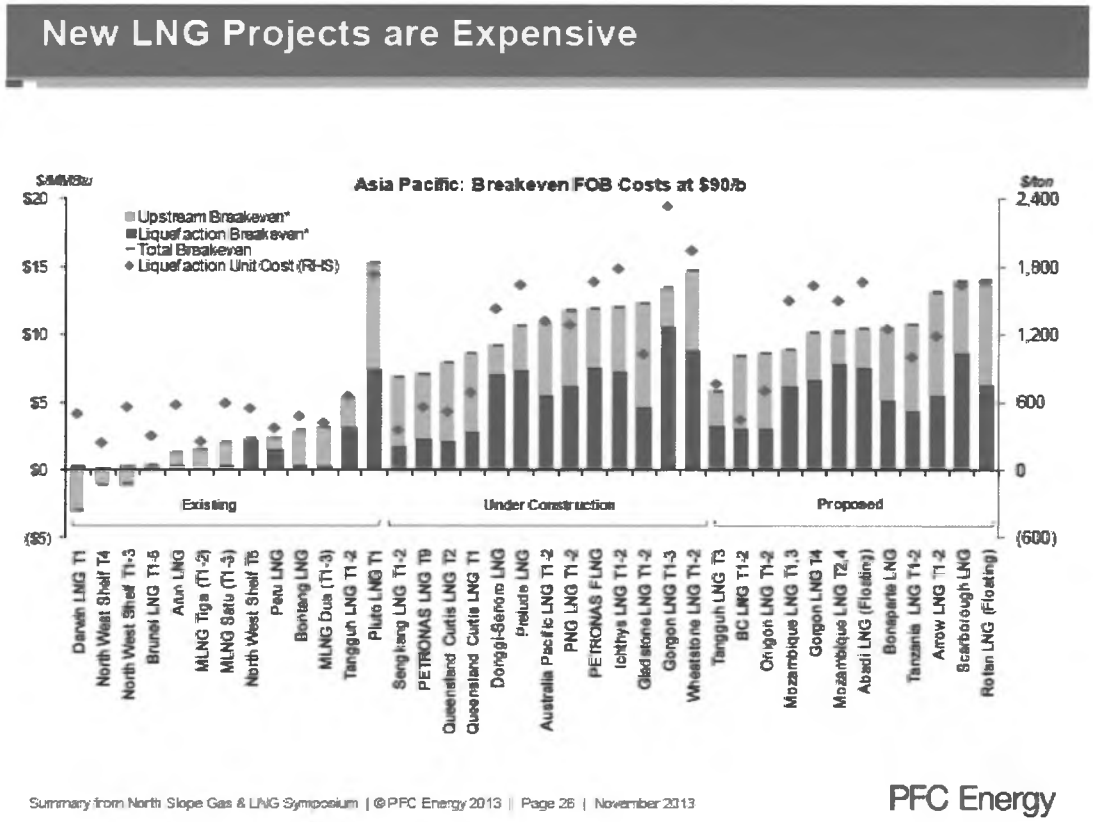
None of this bodes particularly well for Alaska. In 2012 the North Slope producers estimated the cost of the project at $45-$65 billion, including gas treatment, pipeline and liquefaction. It is unclear the extent to which this also includes the upstream costs for large-scale development at Pt. Thomson, which will be considerable.[3] It is likely inflation has occurred since these numbers were released.

Because of the considerable length of the pipeline, a burden no other project has, Alaska is one of the largest and most expensive of all projects. At a $45 billion cost, the tariff for gas treatment, pipeline, liquefaction, and marine transportation would be near $12/mmbtu. Alaska's

[1] Enalytica, "Natural Gas Market Outlook & Fundamentals of LNG Business," Presentation for the Alaska State Legislature, January 28, 2014, p. 21.
[2] The formula is Henry Hub + 15% + $3 liquefaction + shipping. Last year this was in the $10-$11/mmbtu range.
[3] Development costs for the large scale natural gas and condensate production at Pt. Thomson could approach $10 billion.

estimated breakeven price is in the $11-$15/mmbtu range[4], while many of the proposed projects are $8-$12/mmbtu. (See Figure 2)[5]

FIGURE 2



In addition, the project is especially challenged in that because of its size, to sell all the gas it will be necessary to capture large shares of the incremental market demand in a short amount of time. These marking limitations have caused project sponsors to nearly halve the proposed volume of gas relative to the previous plan to move gas into North America. This smaller volume sacrifices the benefits of economies of scale.

Each of the three major North Slope producers would need to independently sanction the project within their corporate confines for it to go forward (though some companies could sell gas to other companies on the North Slope).

[4] Assuming the state takes its taxes and royalties as in-kind gas. The breakeven price would be $1-$2/mmbtu higher if it does not. See Section III.A.

[5] The estimated tariff is a nominal levelized amount. The estimated breakeven prices are in 2013 dollars. Due to inflation they will be nominally higher, and may exceed the levelized tariff.

It will be very important for project sponsors to bring down the costs to the low part of the estimated range; otherwise the project will be uncompetitive. This analysis assumes a $45 billion cost for treatment, pipeline, and liquefaction, and $4 billion for the gas share of Pt. Thomson development.

Accordingly, there is risk associated with funds spent or committed now for a project that may not materialize, or may not materialize for a long time.

The second high level observation is that these projects take a long time to put together. It is plausible that if this project does happen, it is not going to happen soon. Achieving commencement of commercial operations by 2024 is an ambitious goal.

The primary factors that will determine when the project is sanctioned are the producers being comfortable that prices will be sufficiently high, they can penetrate the markets, and they can make the Alaska costs competitive. At this point it is uncertain whether those will be achievable, and the state cannot affect those very much. (This is not to undermine the importance of state institutional arrangements.)

There are a myriad of commercial, institutional, and governmental arrangements that need to be established. Given the dramatic increase in the number of LNG projects under development, there are backlogs of orders for equipment and tankers, and labor is scarce. These issues are also creating cost inflation.

However, on the positive side, there is also no short-term "window of opportunity." Asian demand will continue to grow, and prices may rise. Notwithstanding the timely importance of the project to the state, an aggressive timeline to get Alaska gas to market may not be ultimately be in the state's long-term best interests.

Given this will be a 50-year project (or more) worth several billion dollars to the state, it is important to structure it carefully. The state has the time to figure out what is in its best interests without being hurried. At this point in time, if there were to be a better project that begins in, say, 2026, it may be preferable to a sub-optimal one that starts in 2024.

II. Proposed Commercial Arrangements and Legislation

The Heads of Agreement (HOA) between the state, TransCanada, ConocoPhillips, BP, and ExxonMobil provides guiding principles and objectives that would lead to commercial and operating arrangements between parties to develop the project. Particularly, it addresses state participation in the project through ownership of facilities (gas treatment plant, pipeline [in addition to the main line includes the Prudhoe Bay and Pt. Thomson feeder lines], and liquefaction plant and terminal) commensurate with the state's proportion of the total gas (estimated at 20%-25%), along with proposals for the state to take its royalties and production taxes as in-kind gas, pro-expansion principles, and provisions for in-state gas offtake.

The Memorandum of Understanding (MOU) between the state and TransCanada (TC) sets out the ownership arrangements for the state's share of the pipeline (in addition to the main lines

includes the Prudhoe Bay and Pt. Thomson feeder lines) and gas treatment plant (GTP) described above. The MOU takes the state's equity share of the facilities and shifts the ownership to TC in exchange for shipping terms the state finds favorable. The LNG plant is not part of the MOU; TC would not own any of it. The major provisions of the MOU include:

- TC would hold an ownership interest in the GTP and pipeline commensurate with the state's share of the gas (20%-25%). This analysis uses 22%.[6]
- The state would have an option to buy back an equity share in that ownership (22% of the entire GTP and pipeline). The state could buy back up to 40% of that 22% interest, but TC would get at least 14% of the total GTP and pipeline. For instance, if the state's in-kind royalties and taxes were 22% of the total gas, and the state exercised its option to buy 40% of TC's share, TC would get 14% and the state would get 8%. (The state would carry a maximum of 36% [8% of the 22%] of its gas on its own capacity.)
- The state would have only one opportunity to exercise the option: at the earlier of December 31, 2015, or the date of execution of commercial agreements to commence the FEED stage.
- TC's financial structure for the tariff would be 70% debt / 30% equity, with a 12% cost of equity, and a cost of debt of 5%, both subject to plus or minus changes to 30-year U.S. treasuries between the effective date of the MOU and the time of project sanction.
- The state would be prohibited from selling its share (should it exercise the purchase option) to another pipeline company, and TC would have the right of first refusal to buy any interest the state might want to sell. TC has no such limitations.
- If the state or TC terminates the agreement, the state owes TC the net expenses it has occurred since January 1, 2014.

SB 138/HB 277 is the enabling legislation that allows the state to participate in these two transactions, statutorily creating an AGDC subsidiary to manage the state's equity interest, and authorizing the Department of Natural Resources to negotiate terms for project services, development and implementation. It also contains the associated modifications to the lease/royalty and production tax terms.

III. High Level Decisions for the State to Make

The administration has presented its recommended options forward, which calls on the state to have an equity stake in all infrastructure, handing over its gas treatment and pipeline piece to TC, and taking its taxes and royalties as in-kind gas in order to improve the project economics. Does the state want to participate? If so, what are the risk thresholds? What are the options?

The enabling legislation and associated agreements are designed around a scenario for the project that assumes the following:

- The state takes its royalties and production taxes as in-kind gas.

[6] 2.8 bcf/d into treatment: 2.3 bcf/d from Prudhoe Bay (12.5% royalty) and 0.5 bcf/d from Pt. Thomson (14.5% royalty). 10.5% of gross production tax. 2.4 bcf/d marketed.

- The tariffs and expansion provisions will not be regulated by the Federal Energy Regulatory Commission (FERC), or the Regulatory Commission of Alaska (RCA).
- To ensure reasonable operating conditions (tariff, expansion, in-state gas), the state needs to either own the facilities, or partner with a pipeline company that owns the facilities. Accordingly, the state owns a portion of the GTP and pipeline in partnership with TC, and the liquefaction facility commensurate with its in-kind gas.

The issues of whether to take the gas in-kind, whether to own the facilities, and how the facilities will be regulated are major decisions the state needs to come to terms with before engaging in these arrangements. They are discussed below. (In addition, these agreements appear to be structured to amicably transition out of the AGIA arrangement with TC. This issue is discussed in subsequent sections.)

A. In-Kind Gas

Under current practice taxes and royalties are paid in-value. The producers sell the gas and remit to the state its share of the revenues.

Under an in-kind system the state takes its share of the taxes and royalties as the gas itself, and then the state sells it. For many years DNR has taken some of its royalty oil in-kind to sell to in-state refiners.

There is a very compelling reason to take the royalties and production taxes as in-kind gas; doing so benefits the project economics from the producers point of view. When they are taken in-value, the producers have to make the firm transportation commitment for the capacity to treat, pipe, and liquefy the gas. But it is essentially not their gas. Thus they are paying for capacity for someone else's gas. But financially, the liability for the commitment, a ship or pay obligation, is no different than that of ownership. So again, in essence the producers are paying for a large piece of the facilities they do not use.

If the state takes the gas in-kind instead, it would take on the firm transportation commitment and the associated financial liability to ship gas on the capacity it needs.

Given the tight economics of the project, if the producers did not have to incur this commitment it could make a material improvement in the feasibility of the project. It is like a 20%-25% reduction in the capital cost. This could improve the rate of return by 1-2 percentage points, and reduce the breakeven price by $1-$2/mmbtu, depending on price, cost, and hurdle rate. For a project of this size this is a significant impact.

Other benefits of taking the gas in-kind include avoiding conflicts with transportation charges and LNG charges as can occur in the in-value scenario.

The state does not need to own the facilities to take the gas in-kind. It could simply make a firm transportation commitment to a carrier to ship its gas on the capacity procured.

If the state takes its gas in-kind it incurs the burden of marketing the gas. Currently under the in-value arrangement the state has the benefit of having some of the best gas marketers in the world,

the producers, selling the gas. With an in-kind arrangement the state will be competing against these marketers.

The state would need to create a mechanism to market gas. They could pay a professional entity to do this, at a cost of several cents per mmbtu. Or the state could develop its own marketing arm. That would also entail costs. There were several million dollars for this in DNR's fiscal note.

At the time of project sanction the state would have to have a buyer under contract in hand (as well as be comfortable the market supports the project). Otherwise, the state itself would be holding up the project.

It may be possible to structure a side deal with the producers, that in exchange for taking the gas in-kind along with the large commitment, the state could deliver the gas to the producers at some point and have them market it with the rest of their gas.

When taking taxes and royalties in-value, there is a floor of zero for taxes and royalties; the state cannot lose money. The firm transportation commitment with taking the gas in-kind is a ship or pay agreement. The state is compelled to pay to ship the gas whether it actually ships it or not. If the market price is less than the cost to get the gas to market, the state will lose money.

B. Ownership

1. General

Under the proposal the state will partner with TC for ownership of the GTP and pipeline commensurate with its share of the gas, and own the liquefaction facilities itself (including the terminal) commensurate with its share of the gas.

For the GTP and pipeline the state's share would initially be given to TC and the state would have the option of owning up to a 40% portion of that share, with TC getting a minimum of 14% of the entire facilities. So if the state's share of the total gas was 22%, TC would get 14% and the state 8%. (The state would treat and carry a maximum of 36% of its gas on its own capacity.) The state would own its 22% of the total liquefaction facility and LNG terminal itself.

The arguments for state ownership have been previously described in reports by others. These include transparency, alignment of interests with the producers, income (the return on equity), risk sharing, and the proverbial seat at the table.

It is possible that any partnership with the private parties, who generally operate with greater confidentiality than public entities, could limit transparency.

Also, as a shipper, the state would have a greater alignment of interests with the producers, rather than TC, to keep costs down, especially cost containment for expansions.

The other benefit that could accrue from ownership would stem from the possibility of AGDC owning the facilities at attractive financing terms, which could add value to the state's gas. The

capital structure and cost of capital terms (debt/equity ratio and costs of debt and equity) can swing the tariff widely, and better terms can save the state hundreds of millions of dollars a year.

AGDC financing could bring sizeable benefits. Previously AGDC represented they could finance the stand-alone pipeline with 100% debt, through both revenue bonds and backing by the state.[7] The state's credit is rated AAA, and AGDC may be able to procure tax-exempt debt, which generally costs about 25% less than conventional taxable debt. (The latter would provide some insulation from general increases in interest rates.) Both of these result in lower cost debt than is available from conventional pipeline company financing.

Each percentage point reduction in the weighted average cost of capital (WACC) (percentage debt X cost of debt + percentage equity X cost of equity), relative to conventional private terms, is worth about 80 cents/mmbtu in the tariff. By owning 100% of the facilities for the state's share of the gas (22% of the total 2.6 million mmbtu/day[8] [2.4 bcf/d]), each percentage point reduction in the WACC would be worth $165 million per year, or $4.1 billion over 25 years. This is what the state could save for each percentage point reduction if it were able to get it.[9] For example, if AGDC ownership were to be two percentage points less than conventional pipeline costs of capital, such as TC's, it would save the state $8.2 billion over 25 years.)

One of the benefits of the project would be in-state gas for Alaskans. Some of these savings from a lower cost of capital would directly translate into annual savings of hundreds of dollars to households from lower gas bills (which include charges for treatment and the pipe, as well as the gas itself).

AGDC has been appropriated more than $400 million over time to develop the prowess to finance, build, and operate a pipeline. With the producers involved it could be less complex and less risky than the stand-alone pipeline.

About $8 billion in financing was expected for the stand-alone pipeline. For the large export project, at 22% of $45 billion that would be about $10 billion, not significantly different in amount. (The stand-alone pipeline did not incorporate the liquefaction facilities and terminal; this proposal does.) At 100% debt this should not present a cash flow problem to the state. It may have some short-term effect on the state's credit rating, but it would be offset by the potential of the new royalty and tax gas revenues via LNG sales.

It also appears that the state ownership mechanism here has been crafted around the proposition that the tariff and expansion provisions would not be regulated. Some regulation would occur under Section 3 of the Natural Gas Act; but essentially each shipper would place its gas in its own capacity, and the facilities would operate much like industrial transfer lines. This is discussed below.

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[7] AGDC, "Alaska Stand Alone Gas Pipeline: Project Plan," July 1, 2011, p. 4-8.

[8] Assuming 1.07 mmbtu/mcf.

[9] The issue is similar to a mortgage on a house. The difference between 5% and 6% interest on a $250,000 house is $150/month. Over 30 years this would be $54,000 in interest.

Accordingly, under the proposal, in order for the state to get reasonable tariffs and expansion provisions, it is necessary for the state to own the facilities, either alone or with TC, commensurate with its share of the gas, rather than shipping on the producers' capacity. In addition, the state (and TC) entity could be the expansion source of last resort for new shippers, managing expansion terms at reasonable rates.

2. Ownership under the Failure Outcome

In addition to the obvious cash flow issue, the main concern the state should have about getting involved with ownership now is the very non-trivial risk of spending a lot of money and a project not materializing.

The pre-FEED is expected to cost over $400 million, and FEED nearly $2 billion; pre-sanction costs could exceed $2 billion. Certainly it is likely that if problems emerge during pre-FEED the process would not evolve into FEED. And if significant issues appeared during FEED the process could be stopped.

Nevertheless, much of this could be spent before the viability of the project is ascertained, and result in no project. Much of the cost is targeted toward narrowing cost uncertainties. Detailed gas marketing terms cannot be developed until the costs are known in order to assure provisions account for adequate cost recovery. Certainly many other competing projects will simultaneously be in the FEED stages. And if just one of the producers is not comfortable with proceeding at FID, there is no project,

For example, at $2.4 billion, with a 22% share the state's contribution prior to FID (Final Investment Decision) would be $530 million. Under the TC MOU, as discussed in Section IV, regardless of whether the state exercises the ownership option, the state would have to pay TC's development costs for the GTP and pipeline if the project is not sanctioned (about $260 million).

While state participation is commercially valuable to the producers by partnering in the failure risk, the producers can arguably handle this risk better than the state through their own diversification. They are each analyzing many projects around the world, some of which will go forward. So they can handle the risk of Alaska not going forward, because something else will.

The state has no such diversification options, and thus is less capable of handling the risk of laying out a half-billion dollars for naught. The three producers' total capitalized value of $750 billion dwarfs the state's worth.

In addition, under the terms of the MOU the state needs to exercise its ownership option at the earlier of December 31, 2015, or the date of execution of commercial agreements to commence the FEED stage. It is possible the pre-FEED may not be complete by then and the state would be forced to make a very serious commitment with incomplete information.

It might be worth pursuing with the producers the possibility of buying into the project once it has been sanctioned, including reimbursement with interest for the pre-development costs, in exchange for taking the gas in-kind with the associated large commitment.

C. Tariff and Other Regulation

The proposal under the HOA is for a regulatory framework under Section 3 of the Natural Gas Act. FERC has jurisdiction to license facilities that import or export LNG, and the authority to approve applications for siting, construction, expansion, and operation of LNG terminals. Terminals are defined to include "all natural gas facilities located onshore or in state waters that are used to receive, unload, load, store, *transport*, gasify, *liquefy* or *process* (emphases added) natural gas that is imported to the United States from a foreign country, exported to a foreign country from the United States, or transported in interstate commerce by waterborne vessel."

As discussed above, under this arrangement the facilities would not function as either contract carriers or common carriers. Rather, each producer/shipper would place gas in its own equity treatment, pipe, and liquefaction capacity and take the gas out for its own use at the other end. There are no regulated tariffs. It appears there are currently no major gas pipelines in the U.S. treated similarly.

Also as discussed above, ownership by the state/TC has been proposed as a way to assure reasonable shipping rates on its in-kind gas in the absence of tariff regulation. For non-owner producers the state/TC would be the expansion capacity of last resort. The state would develop expansion and tariff terms for them, in short, finding itself in the gas pipeline business.

As an alternative to ownership, it appears the facilities could be regulated by the RCA, particularly the tariff and expansion provisions. (FERC would probably not regulate tariffs since there is no interstate gas involved.) RCA could be granted the legal authority to regulate the export gas (as well as the in-state gas), and ensure reasonable rates. There is precedent in law for the RCA to regulate export gas.

AS 42.08, enacted with HB 4 last year, authorizing the activity of the AGDC , incorporated such regulation on any export gas that was transported through the stand-alone pipeline. Specifically, in AS 42.08.900(7) "in-state natural gas pipeline" is defined as "a natural gas pipeline that transports or will transport natural gas by way of contract carriage." And "natural gas pipeline" is defined in AS 31.25.390 to be " ... a total system of pipe and connected facilities for the transportation, treatment or conditioning, delivery, storage, or further transportation of natural gas, including all pipe, compressor stations, station equipment, and all other facilities used or necessary for an integral line of pipe to carry out transportation of the natural gas." It is not limited to intrastate gas.

Other sections of AS 42.08 lay out how the RCA would regulate gas that goes through such pipelines. In the case of the stand-alone project, it is possible volumes of gas would be transported and liquefied for export, in addition to the volumes used in state.

AS 42.08 does not explicitly address liquefaction facilities, and is not entirely applicable for a large scale LNG export project. But the main point is that it appears the RCA would be able to assert regulatory authority for export gas in new legislation should the legislature want to pursue that option.

Though RCA regulation might be burdensome to the producers, it is generally considered the trade-off in exchange for the natural monopoly bestowed by the right-of-way permit. In the absence of ownership it would be necessary for ensuring reasonable charges, access, and expansion availability on all the facilities.

IV. The Constraints of AGIA

Based on the structure of the proposals, and public comments made by administration officials, it appears that the plan, at least in part, has been crafted out of a desire to avoid a potential lengthy and costly legal fight over ending the AGIA license. Given TC's material role, the proposed deal appears as if is being structured around the administration's perception that it is constrained by AGIA, there is an aggressive time frame to market the gas, and must give TC this role to end the license amicably. These constraints are discussed in the next section.

To be clear, these observations are based on conclusions drawn from examining public information and statements, and the author has no knowledge of the extent to which the administration may have legally analyzed its AGIA options, and no knowledge of what transpired in the negotiating process between the administration and TC in crafting the MOU.

Nothing here is meant to undermine TransCanada's integrity or commercial ability. This is written from the perspective of the state's responsibility to look after its own interests.

For a very long-term endeavor worth several billion dollars to the state, the state should be very careful about structuring the deal based on perceived collateral damage from AGIA. (In many ways it would be the proverbial tail wagging the dog.)

If the enabling legislation is enacted, the state will essentially be giving TC a sole-source contract worth tens of billions of dollars to transport the state's gas.

TC's capital structure and cost of capital terms are laid out in the MOU (see above). Their capitalization terms are certainly not unattractive by conventional private pipeline standards. (There are some FERC regulated natural gas pipelines that have lower costs of debt and equity, and many with higher costs, as well).[10]

In this circumstance only part of the project would be financed for the state's capacity, with the other parts being built and financed by well-capitalized and experienced major international oil companies. The risk is arguably reduced. Also, as discussed below, TC faces no risk of the project not being sanctioned. Looking at the terms on existing pipelines may not be comparable or relevant. Perhaps that is part of the reason why TC came in with the terms it did.

Potential alternative parties could come in needing lower returns. Going out to bid, or negotiation, could generate better terms, especially given the unique situation here. There are

[10] For example, see FERC, Docket EL 12-77-000, Exhibit No. PSCo-24, or Natural Gas Supply Association, "Pipeline Cost Recovery Report," 2005-2009.

many other qualified major natural gas pipeline companies. A lower cost of capital would translate into lower prices to Alaskans for in-state gas. This is discussed below.

Mostly what the state gets out of the proposal is an arrangement for TransCanada to carry the state's gas at reasonable rates, and some expertise in pipeline construction and operation. As discussed prior, a similar, or possibly preferable, result would occur under RCA regulation or 100% AGDC ownership, with the expertise to build and operate the facilities coming largely with the producers' involvement. The extent of TC experience and expertise in gas treatment is unclear.

Absent the constraints of being connected to TC because of AGIA, the state would have additional options for proceeding. First, contrary to the MOU, it could solicit bids for the best terms, which in addition to a potential lower cost of capital, could include a higher ownership share for the state, the ability to divest to whoever it chooses, and more time to decide on ownership. Again, under the MOU the state may have to exercise the ownership option prior to the conclusion of the pre-FEED stage.

Under this proposal it also appears that the state may face very serious risks if the project is not sanctioned (not a trivial possibility), even if it has not exercised the ownership option. If the project is not sanctioned, TC (the Transporter) can terminate the agreement for a number of reason, including failure of the state to execute a firm transportation services agreement (which would likely be the case if the project is not sanctioned), or failure of TC's board at FID to approve the project.[11]

If TC terminates for these reasons, under the MOU the state (the shipper) would owe TC everything it has spent since January 1, 2014. Based on 22% ownership of the GTP and pipe, and estimated pre-FEED and FEED costs of $1.2 billion, this would be about $260 million, plus interest.

The MOU transfers all of the risk of a failed project to the state.[12] By going out to bid a potential alternative partner may be willing to share or absorb some of this risk.

Moreover, if the state should terminate and pay off TC, per the terms of the MOU, if the state participates in a similar project within 5 years, the state must offer TC similar participation terms to this MOU.[13]

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[11] See Midstream Services Term Sheet, Section 9:
Termination Event: Transporter Rights to Terminate (Transporter Termination Event):
- Shipper fails to execute FTSA by December 31, 2015
- At FID, if all Transporter corporate/Board approvals have not been obtained

[12] See Midstream Services Term Sheet, Section 8:
Development Cost Reimbursement:
If Shipper or Transporter exercises its right to terminate pursuant to any of the Termination Events set forth below (Section 9), the Shipper shall pay Transporter for all development costs incurred by Transporter after December 31, 2013 ...

[13] See Midstream Services Term Sheet, Section 9: Conveyance of Transporter Alaska LNG Project to Shipper

The absence of AGIA constraints could also open up the possibility through AGDC for the state of owning 100% of the capacity to ship (including treatment, pipe, and liquefaction) its in-kind gas in its own capacity. AGDC financing could bring significant benefits relative to TC.

As discussed above, AGDC has represented they could finance with 100% debt, through both backing by the state and revenue bonds. It is unclear what the portion of each would be. For the portion backed by the state, the state has a lower cost of debt than TC; the state is rated AAA by Standard & Poor's, TC is A-. That alone is worth about one percentage point in the cost of debt in today's credit markets.

AGDC also represented they could use tax-exempt debt. Generally this costs about 25% less than taxable debt. AGDC's credit has never been rated.

The above discussion in Section III.B.1 described how if the state itself owned 22% of all the facilities, each percentage point it could save in the cost of capital from AGDC financing would be worth $165 million per year, or $4.1 billion over 25 years.

If the state only owns 8% of the GTP and pipeline due to TC's other ownership share, and the state owns the full 22% of the liquefaction facilities and terminal, that would be a blended 69% share of all the facilities commensurate with its gas.[14] TC would own the other 31%.

By foregoing this 31%, each percentage point reduction relative to TC that it could have realized from AGDC ownership would cost the state $51 million per year, or $1.3 billion over 25 years.

For example, if AGDC could save 2 percentage points over TC, TC's ownership would cost the state $2.6 billion over 25 years.

One of the benefits of the project is in-state gas for Alaskans. Some of this cost would be paid for by Alaskan consumers as these higher costs would translate directly to their gas bill (which will charge for treatment and pipe in addition to the gas itself). The loss of a two percentage point reduction, for example, in the cost of capital on the portion of the GTP and pipe that TC is to own, could cost each household several hundred dollars annually.

TransCanada may have exercised bargaining leverage over the state to let the state extricate itself of AGIA. It may be useful for the state to do a deliberative analysis as to exactly what the state's exposure is, and whether there are better alternatives. A high level analysis is contained in the next section.

[14] The state's share of the facilities commensurate with its in-kind gas is 22%. The total cost is $45 billion. The GTP and pipe are $22 billion (49% of the total). The liquefaction facility is $23 billion (51% of the total). The state would have 36 % of the 22% share of the GTP and pipe (8%/22%), and 100% of the liquefaction facility. This would be 36% of the 49% (18%) and 100% of the 51% (51%) for a total of 69%.

V. Getting Free from the Constraints of AGIA

Insofar as the proposal is a) designed around the administration's perception that it is bound by AGIA, and b) because of the perceived time urgency of the project is not able to pursue potential legal remedies, and c) is thus conveying this role to TC, these constraints are limiting the state's options. It may be useful to explore legally the extent to which the state may not be so bound. There may be some legal arguments that the state is not so confined, and the state could proceed how it wants without incurring an AGIA liability. This could very well slow some of the process down.

To be clear, while the author is not an attorney, he is well-versed in AGIA and has consulted with attorneys in relation to this section. But as such, the forthcoming analysis should not be considered a professional legal analysis. The legislature may want to consider securing legal counsel to further explore its options under AGIA.

Certainly the state does not have a moral obligation to TC. TC willingly took on risks when it became the AGIA licensee, as did the state. To date the state has incurred more costs than TC.

A. Abandonment of Project

The easiest way out of the AGIA license is to abandon the project as uneconomic under AS 43.90.240. Under that clause, if the predicted costs and prices are such that the project is not economically feasible, the license can be terminated. If the parties disagree the issue goes to arbitration.

The original license was for a project to North America, which everyone agrees is now uneconomic pursuant to the large volumes of shale gas that have pushed prices down. These issues are cited in both the HOA and MOU.

Under AS 43.90.210 it is possible to modify or amend the project plan. In 2012 the administration and TC agreed to modify the plan to be an LNG export project, rather than a pipeline to North America. However, it is possible the modification was not made in compliance with the statute. The rationale for that follows. If this were the case, the default plan could still be for the North America project, which would be uneconomic, and the license could be legally terminated.

There are three possible reasons the project plan modification was not made within the provisions of the statute. The first two of these were spelled out in a memo by from Donald Bullock, Legislative Legal Services counsel, to Rep. Hawker on February 15, 2013.[15]

First, counsel opined that changing from the North America to the LNG export project is such a drastic transformation that it is more than just an amendment or modification, and nothing like the detail or scrutiny that accompanied the original application was applied:

[15] Memo from Donald M. Bullock, Jr. to Rep. Mike Hawker, "Assurances to a project licensed under the Alaska Gasline Inducement Act (Work Order No. 28-LS0457)," February 15, 2013.

> The commissioners specifically rejected an LNG option in their recommendation to the legislature. Therefore, under the terms of AGIA, the project licensed under AGIA is the project from the North Slope through Canada. If the route through Canada is the licensed project, changing the project to an LNG project is not a modification to the licensed project, but is a rejection of the AGIA project.
>
> Thus while TransCanada was open to soliciting interest in shipping gas to Valdez and expressed that possibility in its application to FERC, the project pitched under AGIA to the commissioners and the legislature was the highway project, that is, the project to the Canadian border.

Moreover, in recitals 11 and 12 in the MOU state that:

> Because it is not economically feasible that *two* (emphasis added) large-scale pipeline projects will be developed concurrently to transport Alaska North Slope natural gas to market, the Commissioners have committed to consider commercial agreements executed by and between the State, TADI and the ANS producer s for development of the Alaska LNG project as material evidence that the Licensee's AGIA licensed project is uneconomic as provide in AS 43.90.240(a). ... The Licensee has committed that upon the occurrence of the Trigger Event and the execution of the Transition Agreements, the Licensee will agree that the project licensed under the AGIA license is uneconomic within the meaning of AS 43.90.240(a).

The implication of the recitals are that since the LNG project is being pursued, it is not uneconomic, so the North American project must be uneconomic. And since the abandonment clause is being invoked, the North American project must be the AGIA project subject to the abandonment clause.

Second, per AS 43.90.210, any modification must be consistent with the requirements of AS 43.90.130, the original application requirements. This includes 20 requirements. These were not part of the modification process. For instance, AS 43.90.130(2)(D)(ii) requires a thorough description of the project, including:

> the marine transportation services to be provided and a description of proposed rate-making methodologies; an estimate of rates and charges for all services by third parties; a detailed description of all proposed access and tariff terms for liquefaction services or, if third parties would perform liquefaction services, identification of the third parties and the terms applicable to the liquefaction services; a complete description of the marine segment of the project, including the proposed ownership, control, and cost of liquefied natural gas tankers, the management of shipping services, liquefied natural gas export, destination, regasification facilities, and pipeline facilities needed for transport to market destinations, and the entity or entities that would be required to obtain necessary export permits and licenses or a certificate of public convenience and necessity from the Federal Energy Regulatory Commission for the transportation of liquefied natural gas in interstate commerce if United States markets are proposed; and all rights-of-way or authorizations required from a foreign country;

To the author's knowledge all of these have never been submitted for the modification. This information was publicly submitted in the original license application.

Third, another section of AS 43.90.130, section 7, calls for the licensee to propose and support rolled-in rates for expansion costs. Subsequent to the 2012 plan modification, TransCanada has been working jointly with the three producers, who are prime players in the plan modification. As the latest AGIA Fund Disbursement Report says:

> Thus for the first time in this project's history, the APP and the major Alaska North Slope (ANS) Producers (ExxonMobil, BP, and ConocoPhillips) have aligned under the AGIA framework to explore and develop a concept for an LNG project and associated pipeline through the state to tidewater in South-central Alaska.[16]

It is not unreasonable to assume that state AGIA reimbursements are flowing through TC directly to the producers for their share of the work. In any event, for all intents and purposes the three producers are functioning as de facto co-licensees, being the beneficiary of the AGIA inducements intended for the licensee. However, the producers have never supported rolled-in rates, but have actively opposed them.

For these reasons it is possible the plan modification may have been out of compliance, making the North American project the active plan. Insofar as it is clearly uneconomic, this would provide a vehicle for abandoning the license. If this were the case there may be legal remedies available, such as rescinding the plan modification. This would open up other financially preferable options to the state.

B. License Project Assurances

If the project is not abandoned as uneconomic, and the state were to proceed as it wants without TC, there is a risk it could create legal and financial exposure through the license project assurances clause in AGIA, AS 43.90.440. The clause says:

> AS 43.90.440(a) Except as otherwise provided in this chapter, the state grants a licensee assurances that the licensee has exclusive enjoyment of the inducements provided under this chapter before the commencement of commercial operations. If, before the commencement of commercial operations, the state extends to another person preferential royalty or tax treatment or grant of state money for the purpose of facilitating the construction of a competing natural gas pipeline project in this state, and if the licensee is in compliance with the requirements of the license and with the requirements of state and federal statutes and regulations relevant to the project, the licensee is entitled to payment from the state of an amount equal to three times the total amount of the expenditures incurred and paid by the licensee that are qualified expenditures for the purposes of AS 43.90.110 that the licensee incurred in developing the licensee's project before the date that the state first extended preferential treatment to another person.

[16] State of Alaska Department of Revenue and Natural Resources, "AGIA Fund Disbursement Report," Jan. 25, 2013, pp. 3-4.

So the question is whether the state would incur a liability under this section were it to proceed to own the facilities and modify taxes and lease terms. (If the license were abandoned as uneconomic the license project assurances disappear.)

Much in the clause is ambiguous, particularly:

- The meaning of "preferential" (line 4)
- The meaning of "grant of state money" (line 5)
- Whether the payment (line 12) is based on the licensee's gross or net expenditures

Regarding the meaning of "preferential," in hearings on the AGIA bill in 2007, administration officials testified that the intent of AGIA was never to restrict the legislature's ability to look at taxes and royalties:

> The word "preferential" is key because there is no intent to restrict the legislature's ability to look at taxes. If a future legislature decides to modify production taxes, nothing in the bill prohibits the legislature from changing tax rates.
>
> ... changing the tax rate to influence a pipeline project ... isn't a preferential tax change; everybody's affected by it ...
>
> By statute DNR is authorized to look at leases and agree to modify the royalty rates for leases that have been unitized. ... Another area in statute allows DNR to negotiate a more favorable royalty rate when a lessee can show by clear and convincing evidence that development in a particular field is challenged. ... These are existing statutes that apply under specific conditions; their focus isn't to support a specific competing gas pipeline.[17]

These sentiments were echoed by legislative legal counsel Donald Bullock both in committee testimony,[18] and in his aforementioned 2013 memo.

Any law of general applicability isn't preferential treatment; everybody is affected by it. It could apply just as well to a bullet line, a gas-to-liquids project, ice-breaking LNG tankers out of Prudhoe Bay, a pipeline to North America, or a different LNG export project.

As far as "grants of state money" are concerned, administration officials testified that "grant" means an "outright unfettered financial grant."[19] (Perhaps it could be considered donations.) Arguably, buying equity in the facilities may not a grant; the state is making an appropriation and paying for an asset it is getting in return.

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[17] Testimony of Deputy Commissioner Marcia Davis (Dept. of Revenue) on SB 104 before Senate Judiciary on April 13, 2007.

[18] Testimony of Donald Bullock on HB 177 before House Resources on April 10, 2007.

[19] Testimony of Deputy Commissioner Marcia Davis (Dept. of Revenue) on SB 104 before Senate Judiciary on April 13, 2007.

On the other hand, an appropriation could perhaps be considered a grant. Legislative legal counsel opined that "financial support for a competing pipeline could result in liability under the assurances"[20] (but not for certain).

If appropriations for ownership do create a problem, perhaps the state could take its gas in-kind without ownership, foregoing any appropriation, modify taxes and royalties in laws of general applicability as it sees fit, and be free of AGIA. The license assurances expire after the commencement of commercial operations, and perhaps the state could pursue ownership then.

Under AGIA, before the first open season in 2010 the state was reimbursing TC 50% of their expenditures, and afterwards 90%, up until $500 million. So if treble damages are invoked it is an important difference whether it is based on gross or net expenditures.

Per the latest AGIA Fund Disbursement Report, as of January 2013 TC was expected to have spent cumulatively approximately $550 million through the end of 2013, and the state reimburse them approximately $350 million.[21] Based on those figures, on net they have spent $200 million. Treble damages based on gross would be $1.65 billion. Based on net they would be $600 million, a billion dollar difference. Evidently TC spent less in 2013 than expected, so those figures would be slightly reduced.

On whether the payment is based on the licensee's gross or net expenditures, the administration in committee testimony suggested it would be based on net:

> If the state's share is larger the net to the licensee would be lower so exposure post open season would probably be a lot lower.[22]
>
> The limit would be the amount expended by the licensee, based on the expectation of what the licensee might be spending and depends upon the amount matched by the state.[23]

In the aforementioned 2013 memo legislative legal counsel Donald Bullock also opined that net may be a better interpretation:

> In my opinion the better interpretation is that the payment is on net amount paid by the licensee after reimbursement by the state. The reimbursement of expenditures, the benefit of an Alaska Gasline Inducement Act coordinator under AS 43.90.110(a)(2), and the assurances all reduce the risk of the licensee. Reimbursement by the state already removes a percentage of the risk, and the financial investment of the licensee that remains

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[20] Memo from Donald M. Bullock, Jr. to Rep. Mike Hawker, "Assurances to a project licensed under the Alaska Gasline Inducement Act (Work Order No. 28-LS0457)," February 15, 2013.

[21] State of Alaska Department of Revenue and Natural Resources, "AGIA Fund Disbursement Report," Jan. 25, 2013, p. 10.

[22] Testimony of Deputy Commissioner Marcia Davis (Dept. of Revenue) on SB 104 before Senate Judiciary on April 13, 2007.

[23] Testimony of Commissioner Patrick Galvin (Dept. of Revenue) on HB 277 before House Resources, 2007.

is the percentage not paid and the expenses incurred and not subsidized after the $500,000,000 has been exhausted.

The language in the act may suggest otherwise. The amount (from above) says:

" ... three times the **total** amount of the expenditures incurred and paid by the licensee that are qualified expenditures ... "

There are two other sections in AGIA that involve payments from the state to the licensee. AS 43.90.200 addresses what happens if the licensee does not sanction the project as required. In that case the licensee transfers the FERC certificate to the state, and the licensee gives the state its data if the state wants it. In return the state pays the licensee:

" ... three times the **net** amount of the expenditures incurred and paid by the licensee that are qualified expenditures ... "

When the language means net, it says net.

AS 43.90.240 addresses what happens if the project is abandoned for being uneconomic. Again, the licensee gives the state its data if the state wants it. In return the state pays the licensee:

" ... three times the **net** amount of the expenditures incurred and paid by the licensee that are qualified expenditures ... "

Again, when the language means net, it says net.

In conclusion, the proposal arguably results from two possible perspectives from the administration. First, the administration may believe there is an aggressive time line to move the project, and it would not be fruitful to consider a time consuming legal strategy to try to break from the AGIA process (which could open up several additional preferential options). As discussed above, for a project this important it may be useful for the state not to act in a hurried manner.

Second, as explained above, some of the terms of the MOU create significant fiscal risk for the state. The AGIA constraints may have put the state in a weak bargaining position with TC, which put TC in an advantageous situation.

The state could consider proceeding along the following lines regarding both the abandonment of the project and the license project assurances. Perhaps the administration has done some of this non-publicly:

- Engage TC as to whether they would litigate if the state went in a different direction.
- If they would, assess the state's legal exposure and options.
- If the state believes the risk is reasonable, it could decide to go to court. Obviously that slows things down, and the outcome would not be certain. Some other development

activities could still proceed concurrently. If the state loses in court it could pay the treble damages and the long-run benefits could still exceed the cost.
- If the state believes it does have reasonable exposure, it could consider paying off the treble damages immediately and the long-run benefits could exceed the cost.

Finally, insofar as TC wants this project, the state does have some bargaining strength, and could push back for better terms with TC.

VI. Gas Production Tax

The proposal is for a gross tax rate of 10.5% that can be paid as in-kind gas. As discussed above, taking the gas in-kind improves the project economics, and should be seriously considered. If taxes are taken in-kind, it makes sense to have the tax based on gross to provide stability of volumes.

As far as what is the appropriate rate, as was emphasized last year in the discussion of oil taxes, fair share is what you can get in a competitive environment. Accordingly, it depends on government take among jurisdictions with a similar risk/reward balance as Alaska.

Figure 3 shows government take on LNG projects as derived by Daniel Johnston. These were published in the Black & Veatch report prepared for DNR.

Note there is a wide variation in take. Alaska is a high cost, lower valued, higher risk project. It does have some advantages: it has low gas production costs (the gas is already being produced and shares the costs with the oil), and its reserves are proved up. In addition, with the in-kind mechanism it is taking on more risk and reflects a system more like a production sharing system (PSC), which have higher takes. Accordingly, it would not be unreasonable to look at the middle of the spectrum of government take for a target, perhaps about 70%.

At a $45 billion cost, and a $15/mmbtu price (real 2013 dollars) in Asia, at the proposed 10.5% production tax rate, the estimated government take is 70%.[24] It would vary from 71%-70% at prices from $10-$20/mmbtu, a fairly neutral system. This would appear to be reasonably close to the target range.

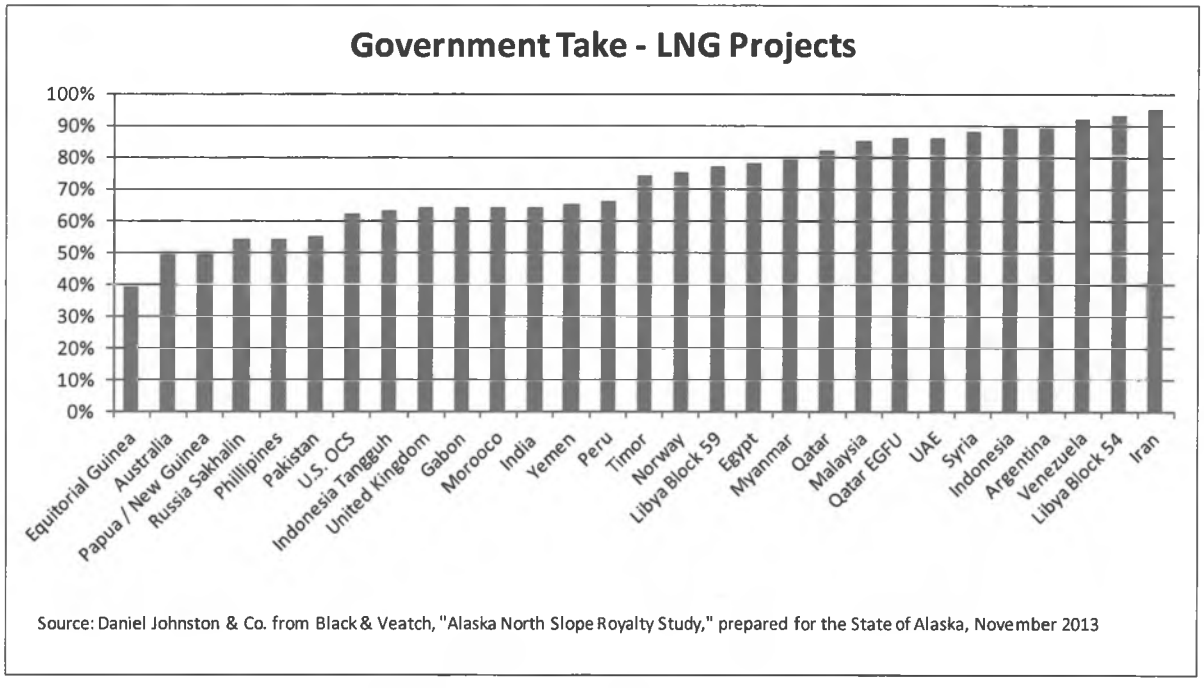
As discussed below, while the tax rate is based on gross, the bill appears to allow the deduction of upstream gas costs against oil production. This will mostly happen with Pt. Thomson. The take numbers above reflect this.

With the state taking its taxes and royalties in-kind, and paying its expenses accordingly, any increase or increase in the tax rate is associated with increases and decreases in the producers'

[24] The state could take its taxes and royalties in-kind associated with either no ownership, partial ownership, or full ownership of the portion of the facilities associated with the capacity it would ship. Insofar as taking the gas in-kind involves a firm transportation commitment financially equivalent to ownership, this analysis of taxation is calculated as if the state takes full ownership of the facilities commensurate with its share of the gas.

and state expenses. Accordingly, as the cash flows simply scale up or down, much of the financial metrics do not change very much. However, undiscounted cash flow, which is very important, certainly moves quite a bit with changes in the tax rate.

FIGURE 3



Source: Daniel Johnston & Co. from Black & Veatch, "Alaska North Slope Royalty Study," prepared for the State of Alaska, November 2013

Some observations on the property tax: Currently the property tax is based on value and as such is very regressive. The higher the cost of the facilities, the more the property tax. It exacerbates the cost problem, especially on something that will cost in excess of $50 billion. In addition, over time there has been a plethora of litigation over the assessed value of the oil pipeline due to the theoretical difficulty of assessing value on such unique assets. Currently every assessment since 2005 is in some stage of adjudication.

Accordingly, as spelled out in Article 9 of the HOA, other project enabling terms, it would be well worth the effort to carefully examine converting the property tax to a cents per mmbtu basis. While clearly the local jurisdictions, who are the main recipients of the tax, need the funds for dealing with local social impacts associated with developments, there is probably not a strong relationship between the cost of the assets and the costs of dealing with the impacts.

Finally, there are two comments on the drafting of the bill. First, in Section 29, where the irrevocable decision to pay the production tax as in-kind gas is made, it may not be clear how the amount of gas is determined. Is it 100% of the gas? A set volume? Can a taxpayer make the decision on a portion of its gas?

Second, as discussed above, in Section 42, AS 43.55.160(h) is amended to say that the annual production tax value for oil is the gross value less expenditures to produce oil or gas. Does it make sense to deduct the costs for producing gas in determining the net value for oil? The proposed tax on gas is a gross tax, and so its rate is lower relative to a tax on net (since net is lower). As written, with the deductibility of the gas expenses, there is essentially a gross tax rate based on net value. The current AS 43.55.165(h) contains provisions for allocating costs between oil and gas. In addition, should there be a company with only gas, it would be unable to deduct its upstream costs and would be at a significant disadvantage.

VII. Conclusion

The administration's proposal may provide a suitable blueprint towards North Slope gas commercialization. It appears that it has been crafted around giving TransCanada an ownership role due to perceived AGIA constraints. Because of these constraints, the state may be making financial sacrifices and foregoing some options.

The main risk of state ownership stems from the possibility of going through an expensive feasibility process with the project not being sanctioned. Should this occur, the state is responsible for TC's costs even if the state does not exercise the ownership option.

The main benefit of state ownership would be the possibility of low cost state financing through AGDC. This could save the state several billion dollars. TC's involvement reduces that benefit by about 30%. Some of this would be paid for by Alaskan consumers in the form of higher gas bills.

If the state feels it needs a partner, TC's involvement eliminates the possibility of going out to bid for the best terms on cost of capital, risk sharing, and ownership percentage.

This proposal reflects an urgency to move forward on the project rapidly, and there may be wisdom to that. For a project of this size, this duration, and this value, an option for the legislature may be to reflect on how the state would proceed if it were not so encumbered. If the alternative is much preferable, it might be worthwhile to pursue.

MARCH 26, 2014

TRANSCANADA PARTICIPATION IN AKLNG PROJECT

PRESENTATION TO HOUSE RESOURCES COMMITTEE

PREPARED FOR THE STATE OF ALASKA

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BLACK & VEATCH PRESENTERS

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MEMORANDUM OF UNDERSTANDING – HIGHLIGHTS OF THE DEAL ON THE TABLE

TC Holds the State's Equity Share in GTP+Pipe

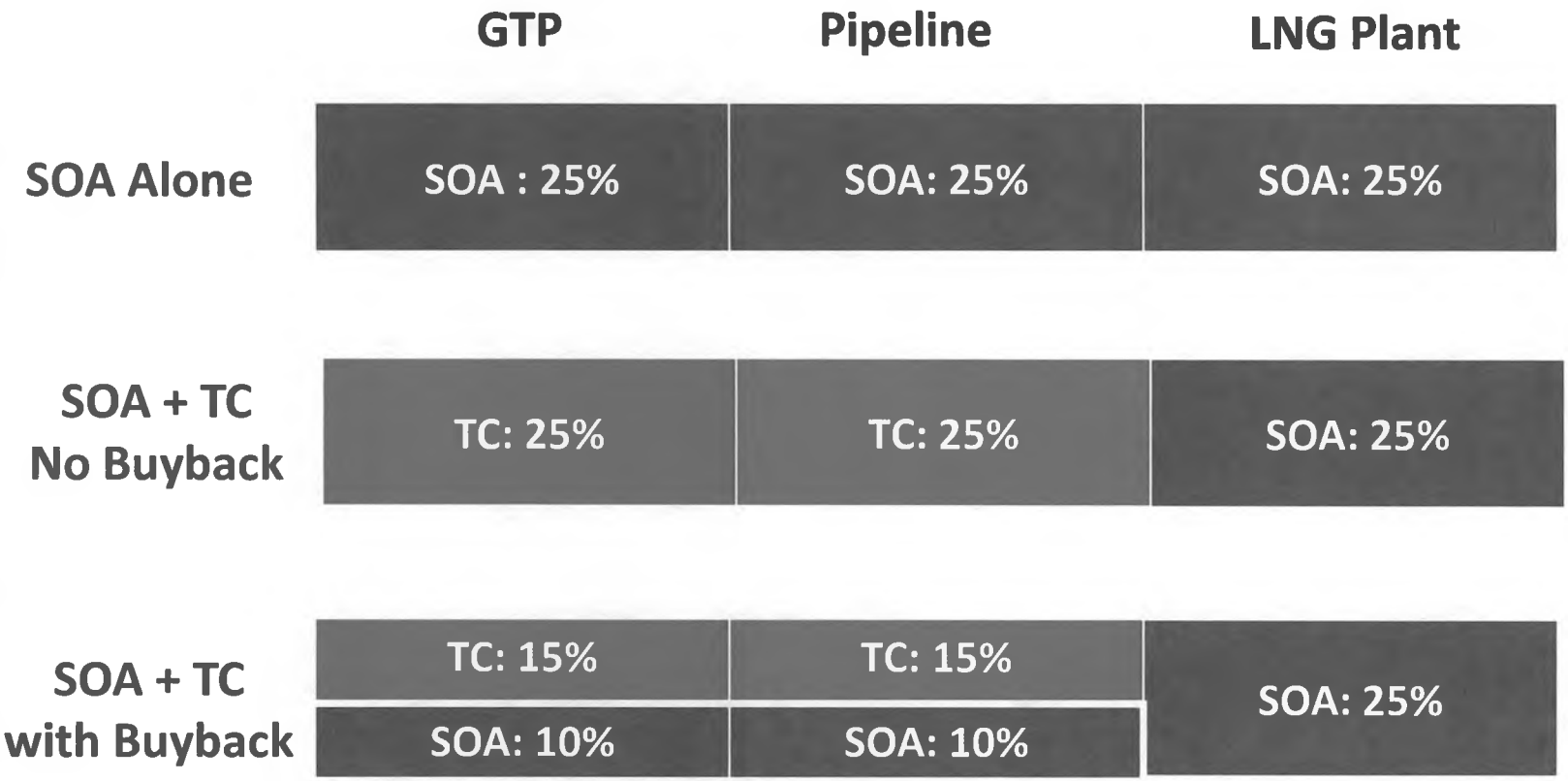
SOA Option to Buy Back 40% of TC's Share at ~FEED

State Commits to 25 Year Transportation Agreement with TC

Agreement Commits TC to a WACC of 6.75%

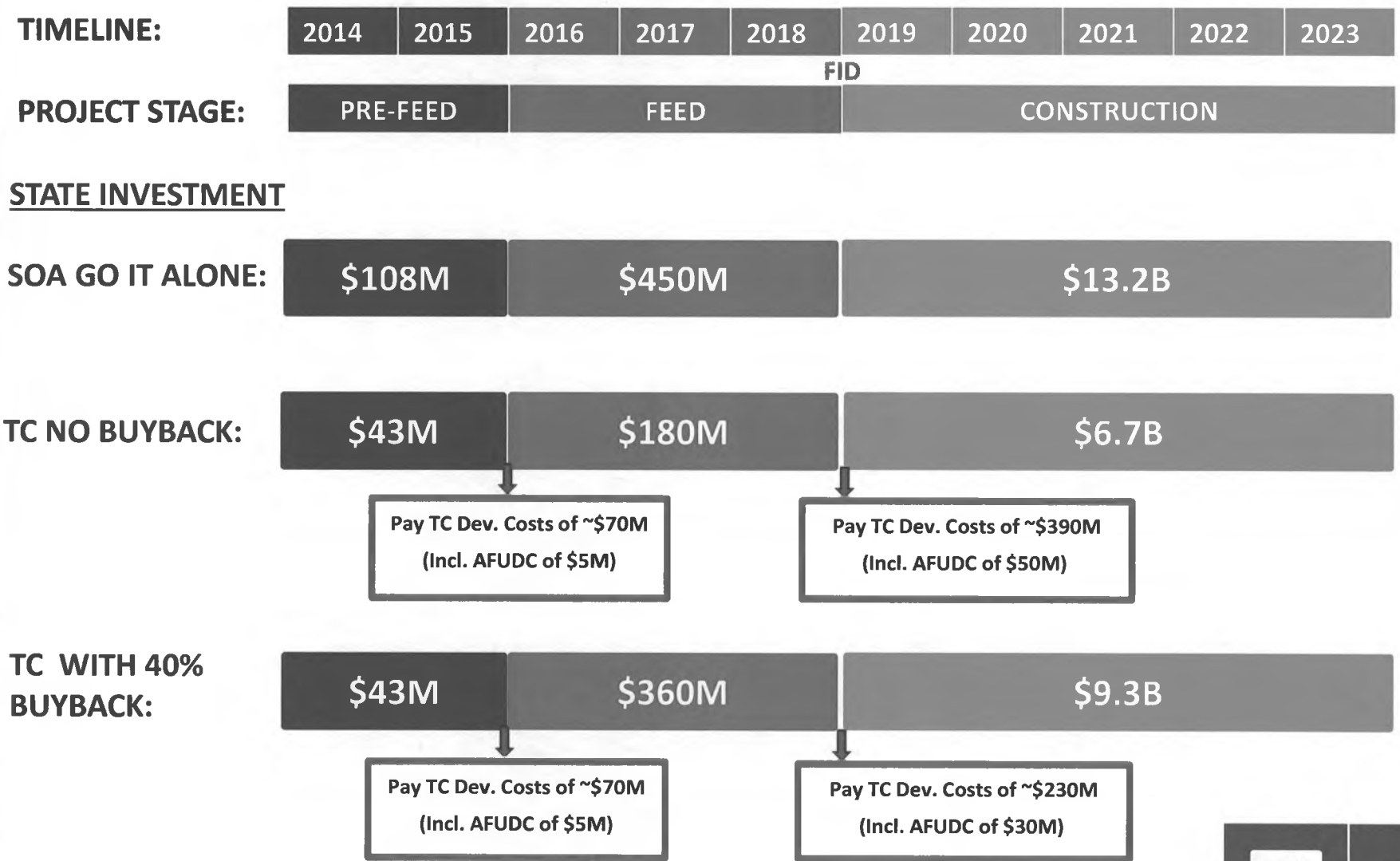
Various Milestones & Off Ramps for SOA and TC

OPTIONS IDENTIFIED BY STATE FOR EQUITY PARTICIPATION



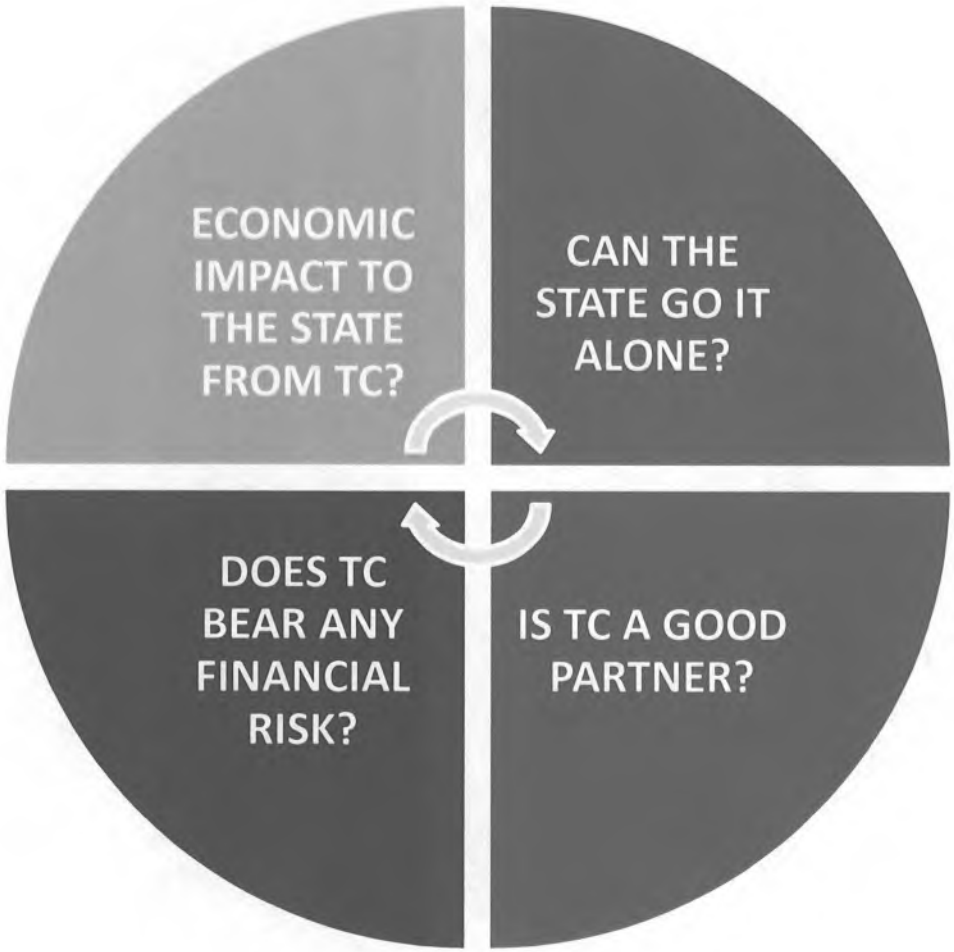
* Assumes 25% State equity participation

IMPLICATIONS OF OPTIONS AND POTENTIAL OFF RAMPS



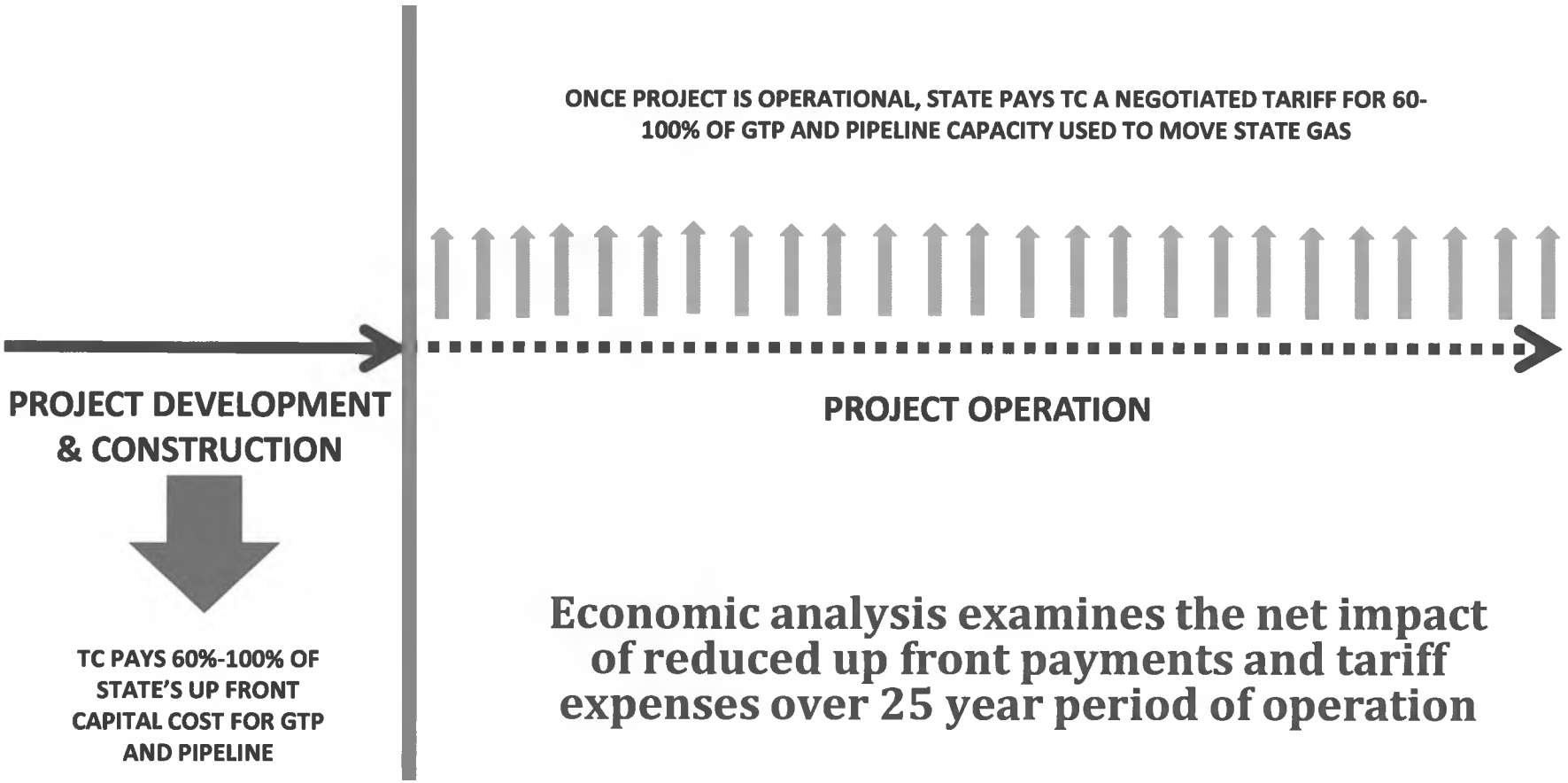
* Assumes 25% State equity participation

KEY QUESTIONS IN LOOKING AT VALUE OF TRANSCANADA'S PARTICIPATION



WHAT IS THE ECONOMIC IMPACT TO STATE FROM TRANSCANADA'S PARTICIPATION?

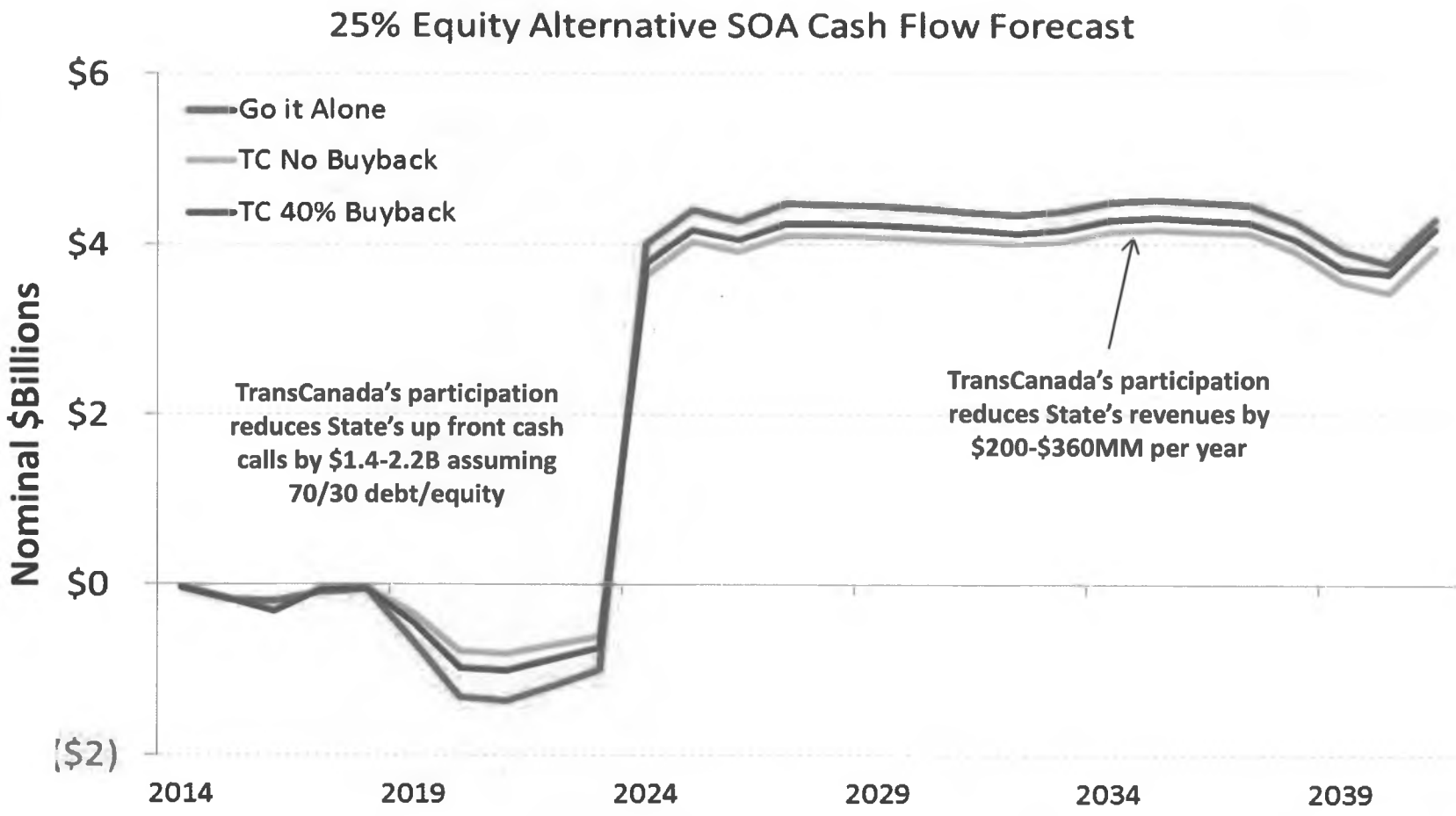
SOA IMPACT



Economic analysis examines the net impact of reduced up front payments and tariff expenses over 25 year period of operation

TRANSCANADA'S PARTICIPATION IMPACTS SOA UP FRONT CASH CALLS AND REVENUES FROM PROJECT

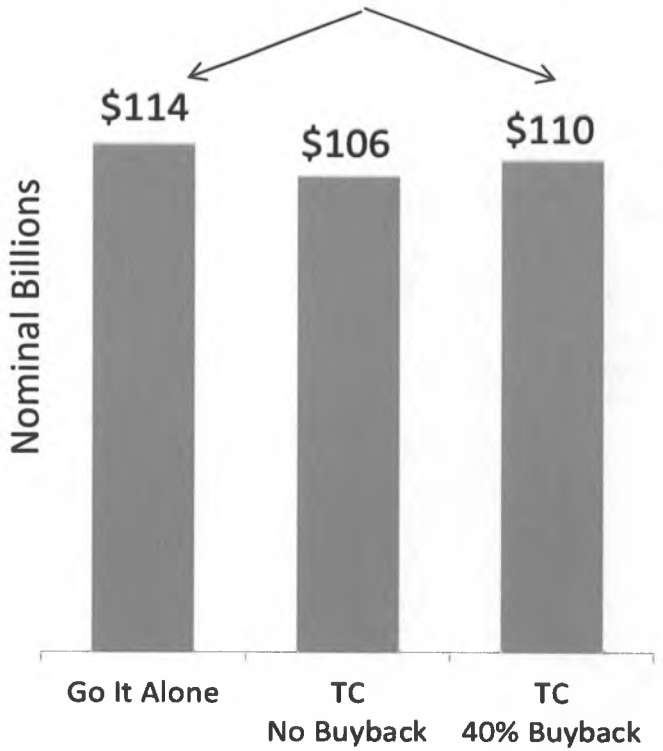
SOA IMPACT



WHAT IS THE ECONOMIC IMPACT TO STATE FROM TRANSCANADA'S PARTICIPATION?

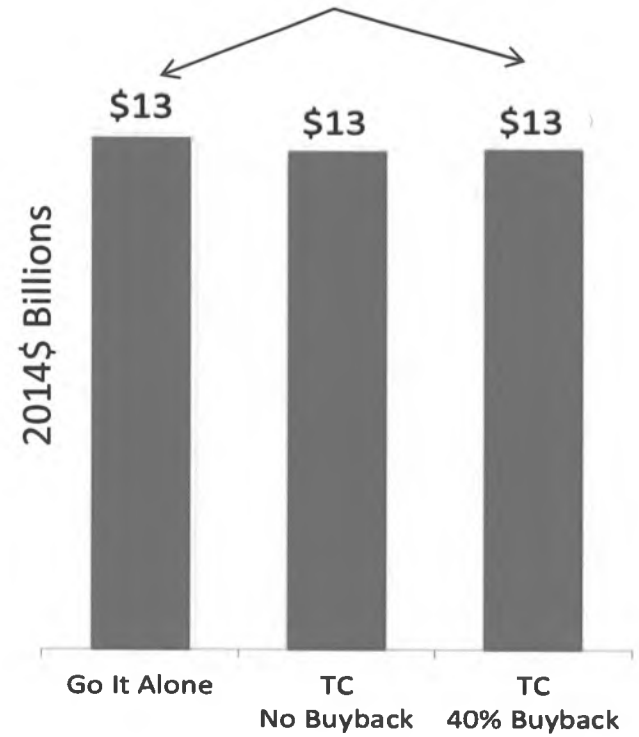
SOA IMPACT

TransCanada participation reduces the State's total cash flows with buy back option



STATE OF ALASKA CASH FLOWS

Minimal impact on the State on an NPV basis with TransCanada participation.



STATE OF ALASKA NPV_{10}

TransCanada's NPV is expected to be $150-$200MM over the initial 25 year period

* Assumes 25% State equity participation

CAN THE STATE GO IT ALONE?

- What are the capital cost and investment implications of going it alone
- What are the debt implications of going it alone?

SOA UPFRONT CAPITAL COST EXPOSURE IS REDUCED THROUGH TC PARTICIPATION

- **Highest risk exposure is prior to project start when cash calls are not supported by project revenues**
- **TransCanada ("TC") participation allows State to retain 20%-25% of gas share while being responsible for only 13%-18% of the upfront costs**
- **This is especially important if cost overruns occur on project**

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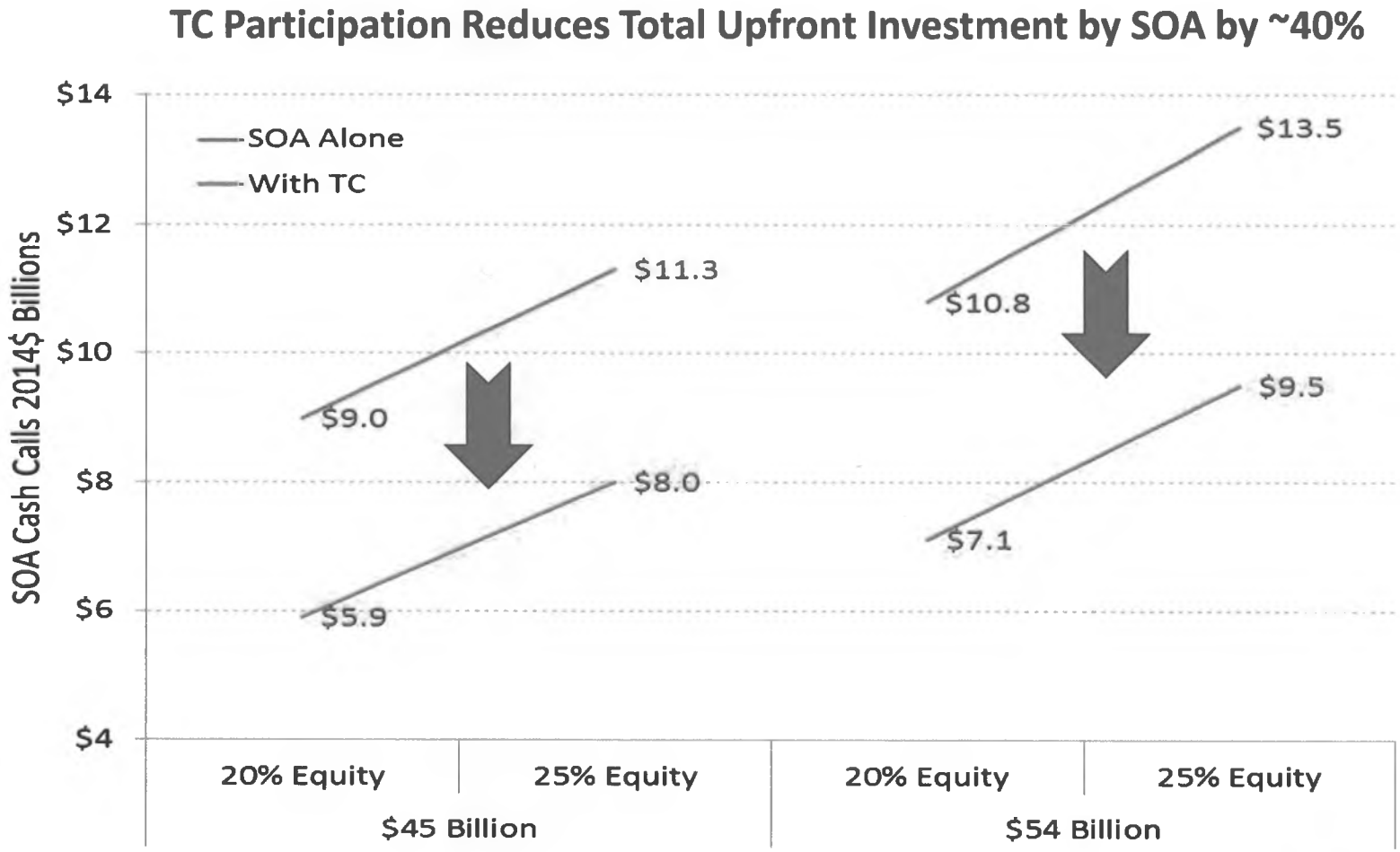
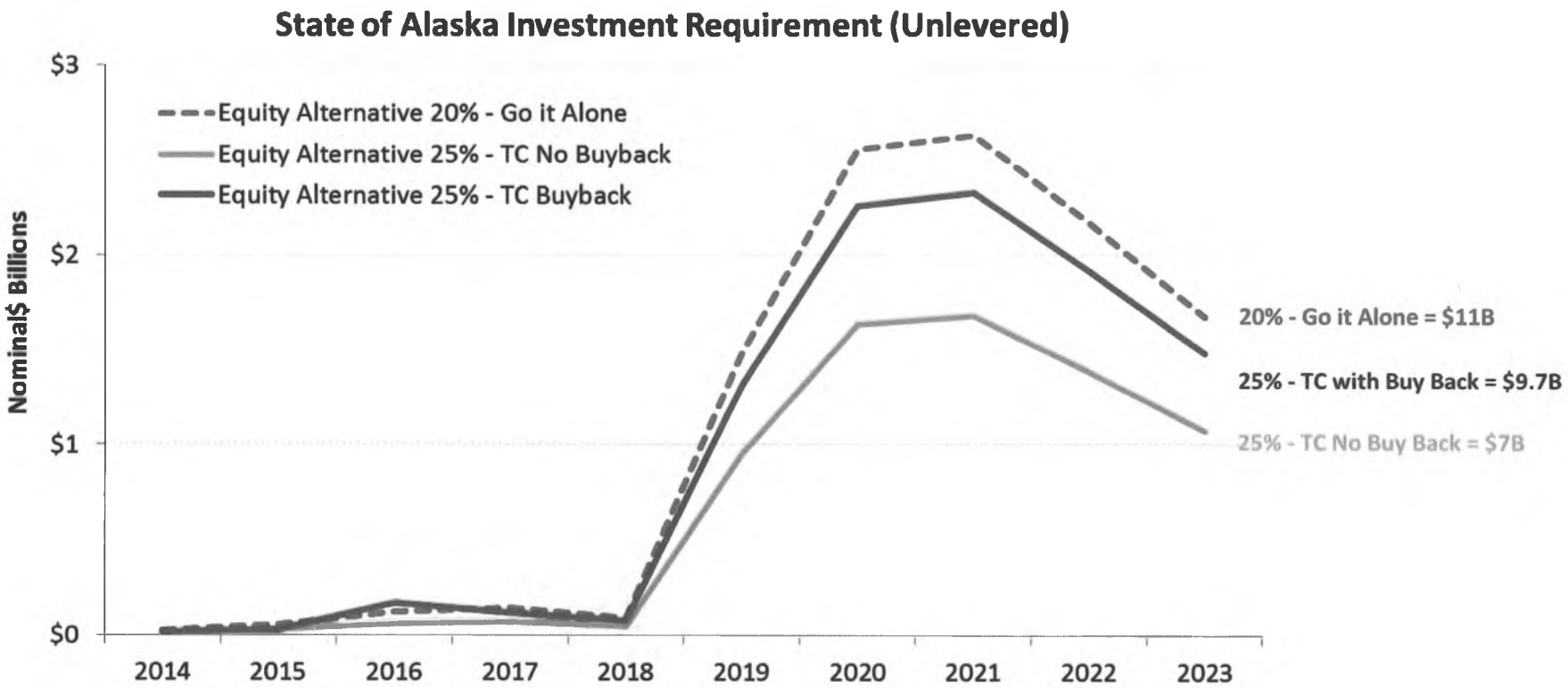
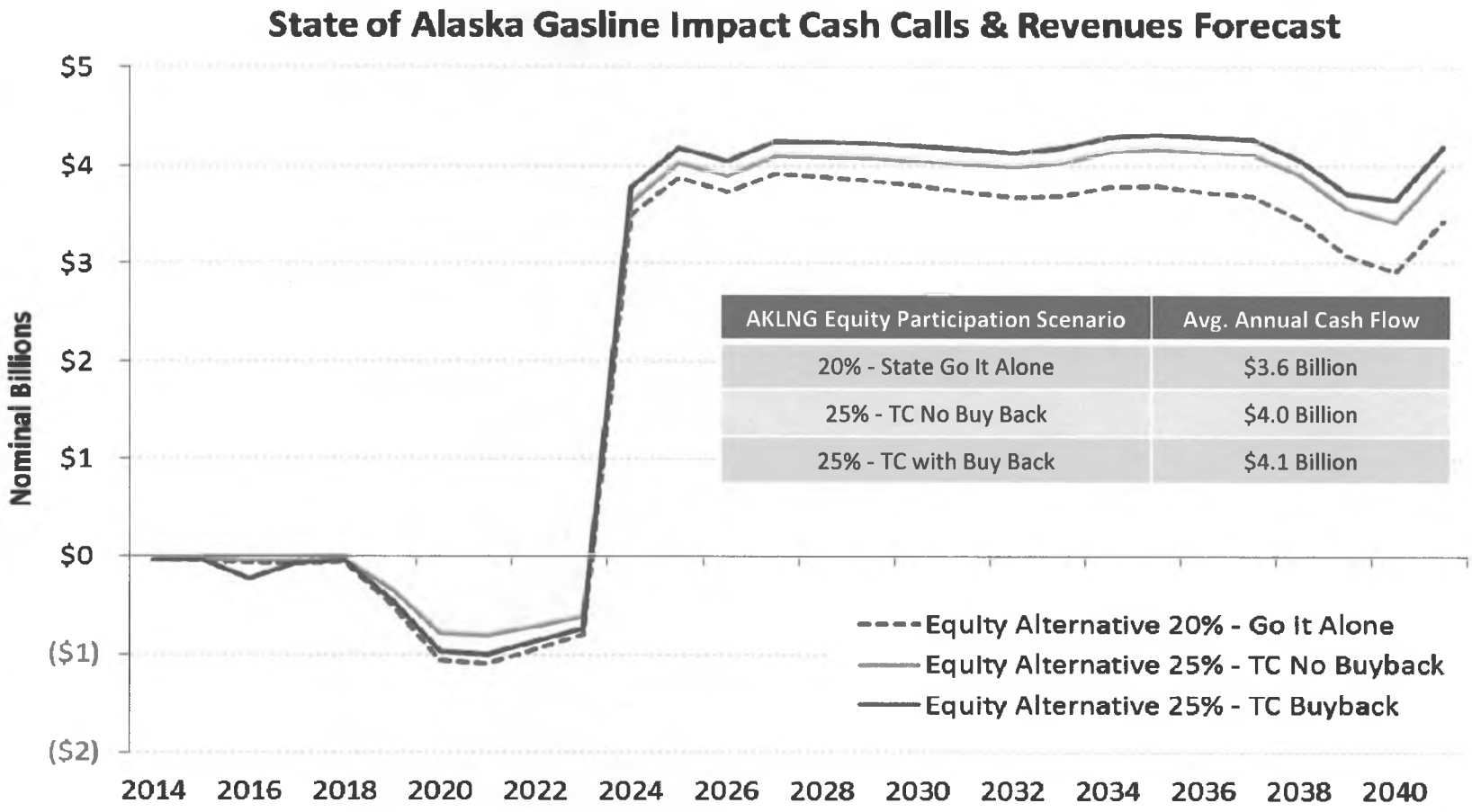


* Assumes State exercises 30%-40% equity buy back with TransCanada

SOA INVESTMENT FOR A 25% OWNERSHIP WITH TC IS EXPECTED TO BE $1.3-$4B LOWER THAN FOR A 20% OWNERSHIP GOING ALONE

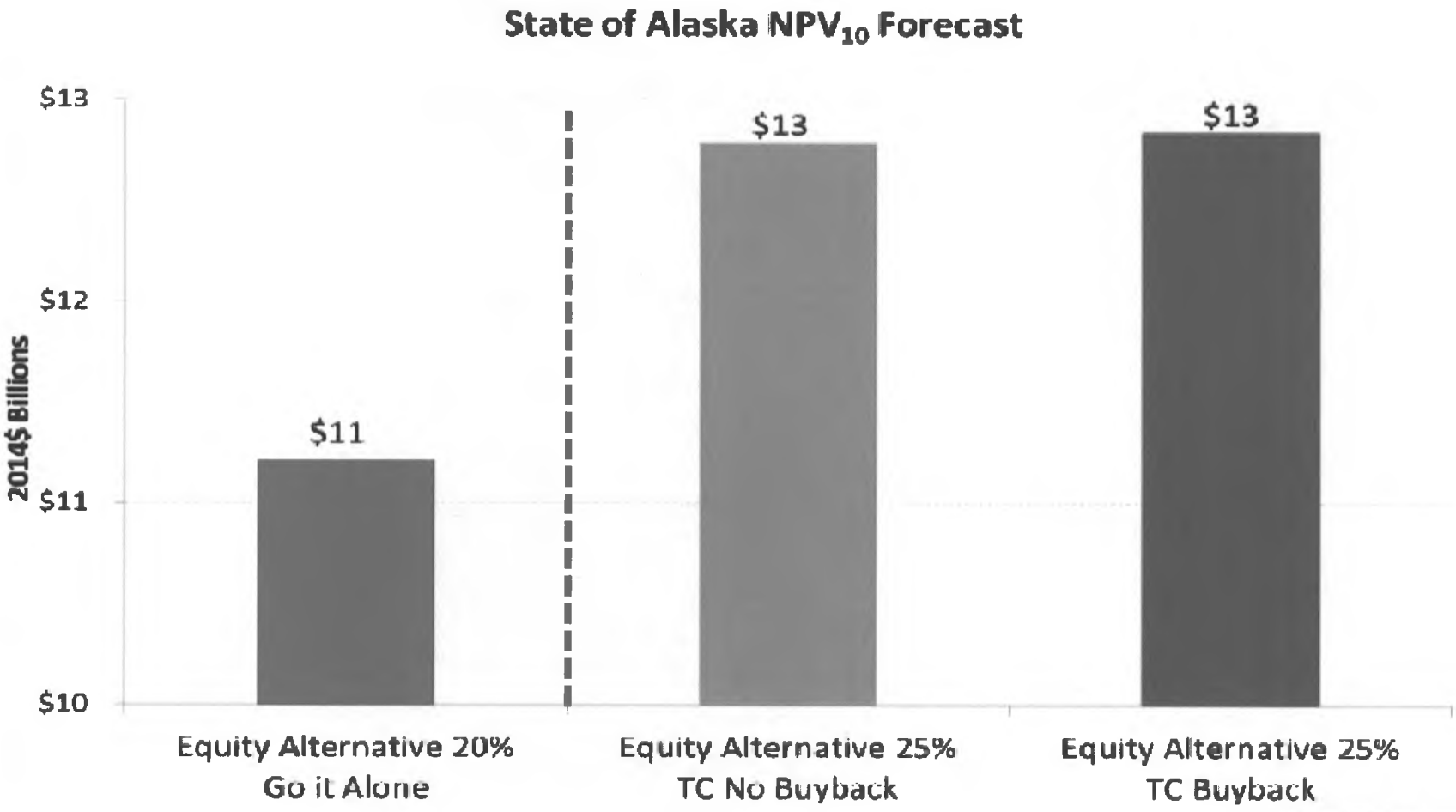


SOA REVENUES FOR A 25% OWNERSHIP WITH TC ARE EXPECTED TO BE $0.4-$0.5B PER YEAR HIGHER THAN FOR A 20% OWNERSHIP GOING ALONE



AKLNG Equity Participation Scenario	Avg. Annual Cash Flow
20% - State Go It Alone	$3.6 Billion
25% - TC No Buy Back	$4.0 Billion
25% - TC with Buy Back	$4.1 Billion

25% OWNERSHIP WITH TC INCREASES STATE OF ALASKA NPV_{10} BY $2B COMPARED TO A 20% OWNERSHIP GOING ALONE



*** NPV calculated over initial 25-year anticipated term of service agreement with TransCanada**

CAN THE STATE GO IT ALONE? - STATE'S DEBT CAPACITY

- **Financing the State's share of the AKLNG Project on the State's balance sheet – key issues:**
  - At what cost of debt?
  - Debt servicing as what % of general fund unrestricted revenue?

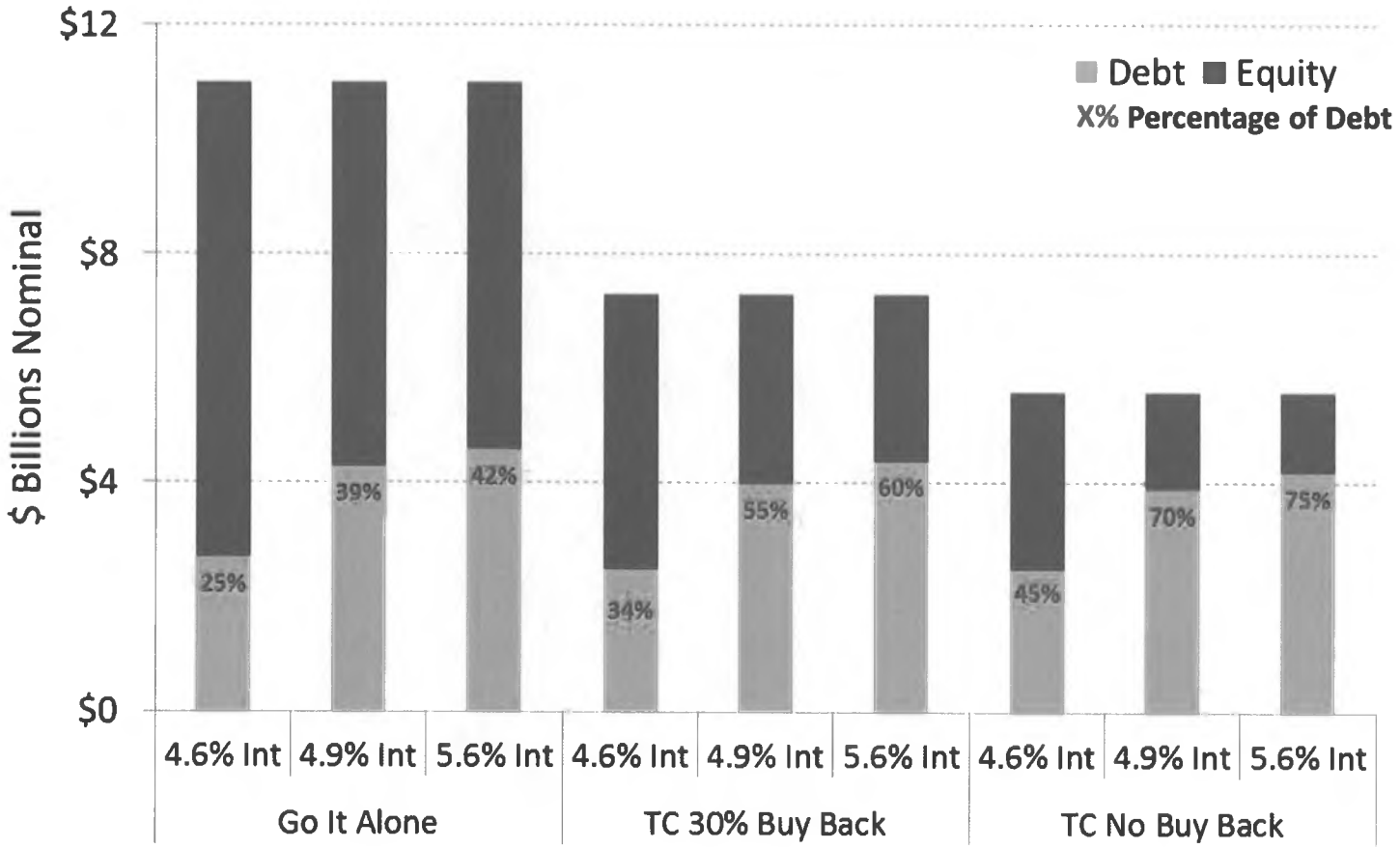
Scenario 1 (lower interest)	• SOA Debt at 4.6% • Debt Service limited to 3% of GFUR
Scenario 2	• SOA Debt at 4.9% • Debt Service limited to 5% of GFUR
Scenario 3 (higher interest)	• SOA Debt at 5.6% • Debt Service limited to 6% of GFUR

*** High-level, indicative assumptions based on input from Department of Revenue**

THE AMOUNT OF CHEAP DEBT AVAILABLE TO THE STATE COULD BE LIMITED

SOA ALONE?

Indicative Levels of Debt for State to Finance 20% Equity Stake in AKLNG Project



*** Analysis based on high-level, indicative assumptions based on input from Department of Revenue. Financing arrangements for the AKLNG project will become clearer further into the development process.**

IS TRANSCANADA A GOOD PARTNER FOR THE STATE OF ALASKA IN THE AKLNG PROJECT?

Extensive experience in building, owning and operating northern pipelines

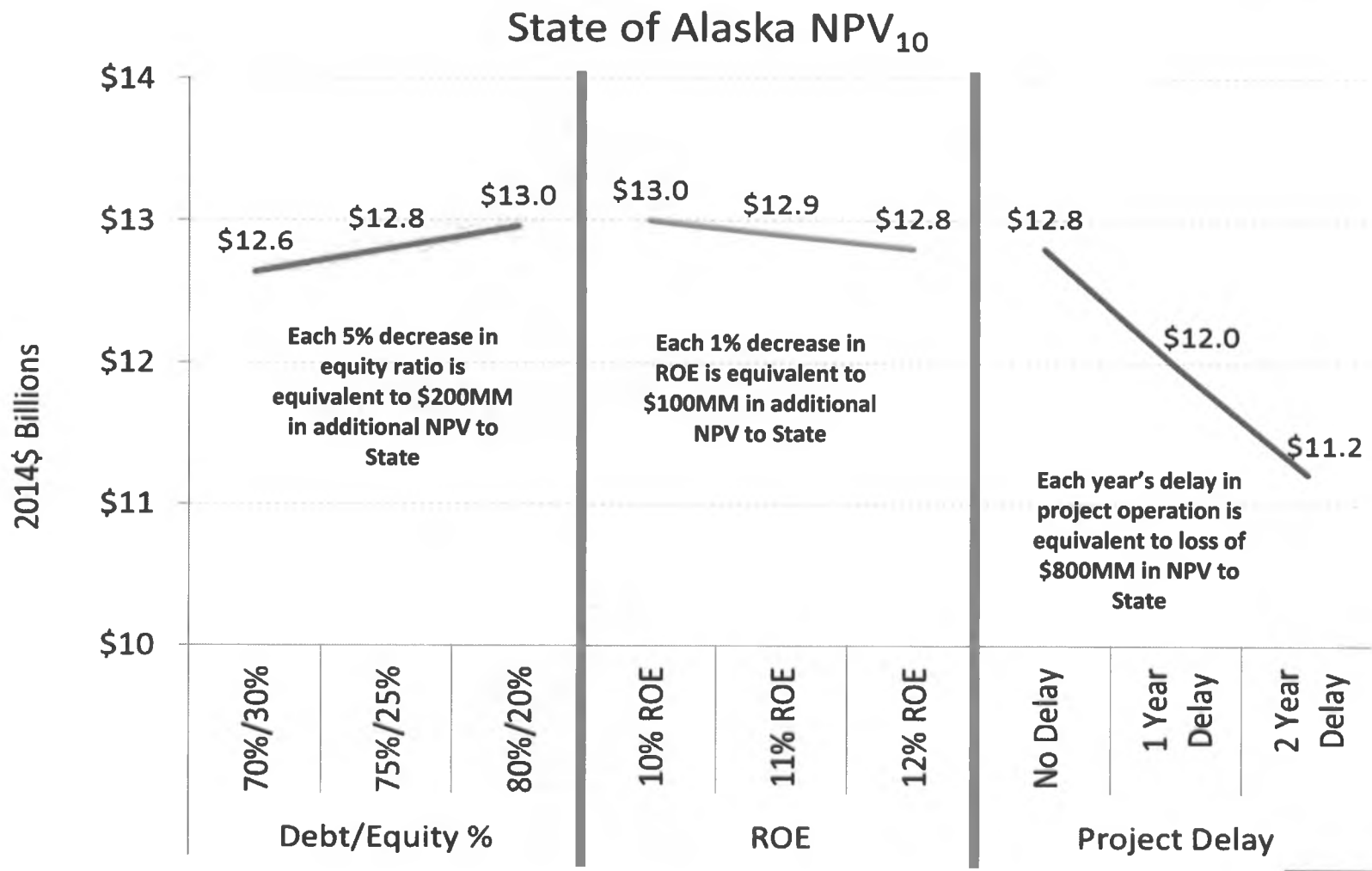
Long history of interest in Alaska Pipeline

Retains momentum in the project

Facilitates expansion

RETAINING MOMENTUM ON PROJECT COULD BE MORE VALUABLE THAN SECURING BETTER COMMERCIAL TERMS

TC AS PARTNER



DOES TRANSCANADA BEAR ANY FINANCIAL RISK?

TransCanada has committed to the following terms for providing treating and transportation services to the State

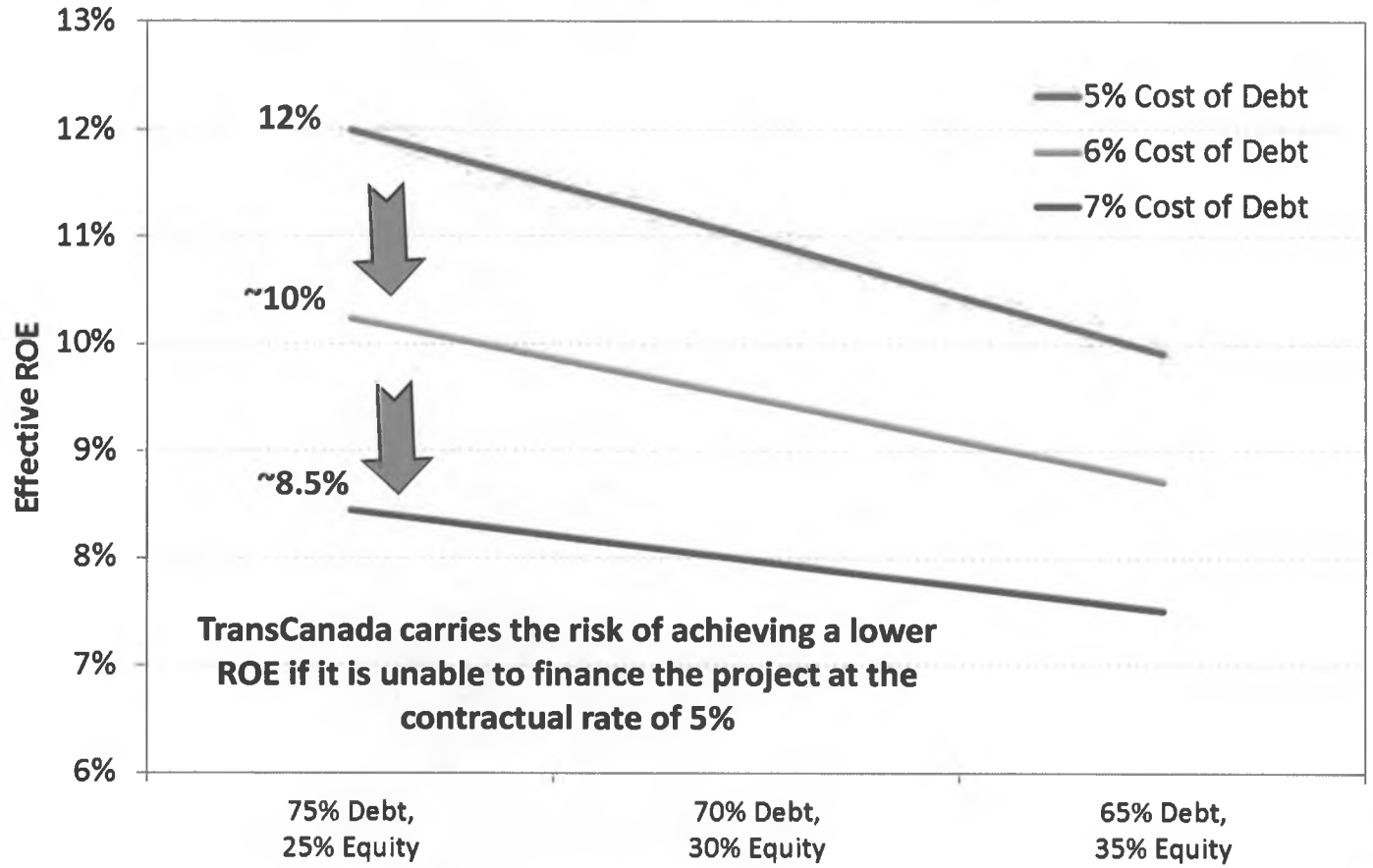
- D/E split of 75%/25%
- Return on equity of 12%; Cost of debt of 5%

Given the scale of this project and the uncertainties associated with it, financing remains a significant risk

Locking in this capital structure before actual financing arrangements have been made for the project places a risk on TransCanada of under-earning its expected return on equity and eroding its expected NPV from the project

DOES TRANSCANADA BEAR ANY FINANCIAL RISK?

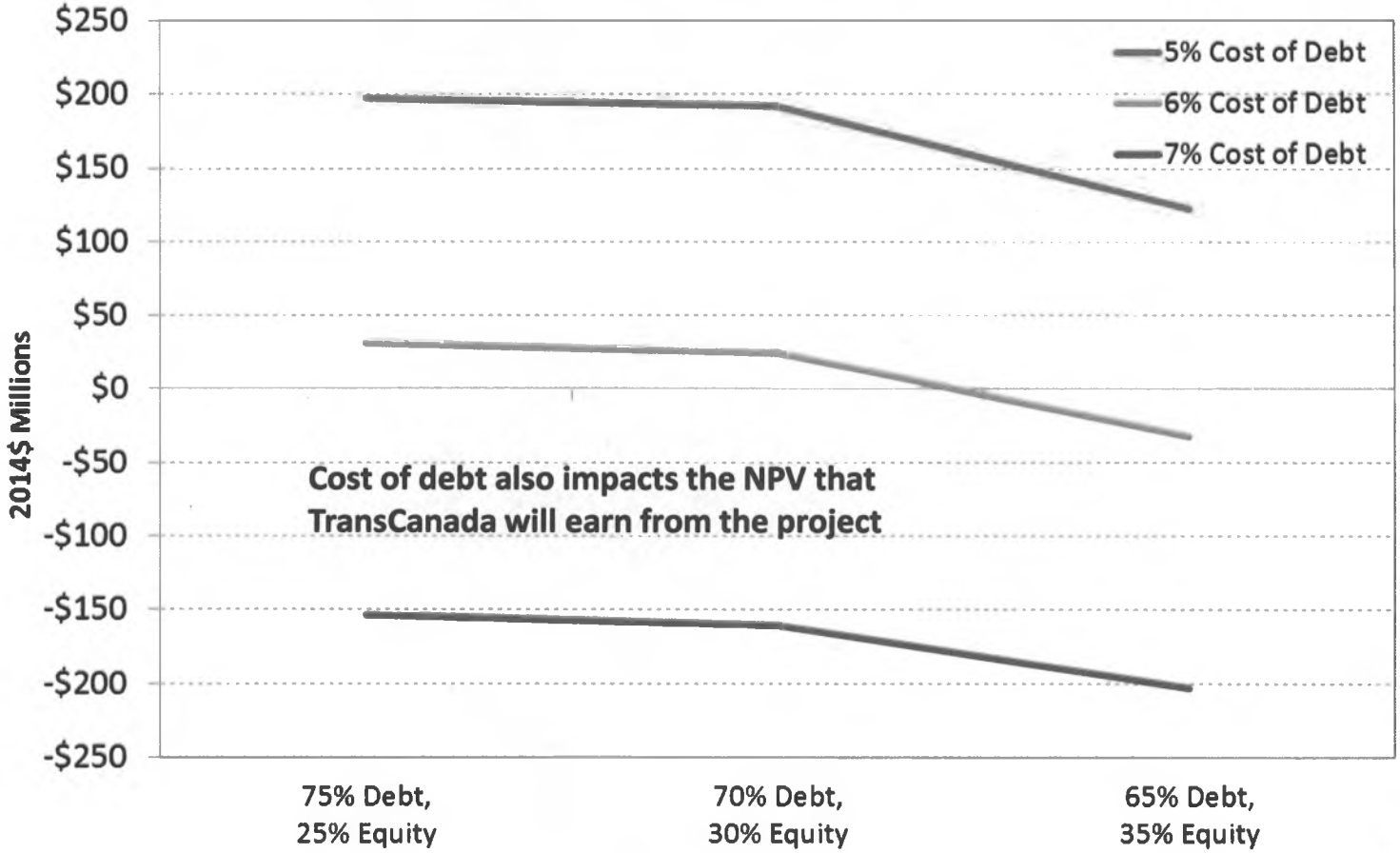
TRANSCANADA EFFECTIVE ROE UNDER DIFFERENT FINANCING ARRANGEMENTS



* Assumes 25% State equity participation without State exercising buy back option

DOES TC BEAR ANY FINANCIAL RISK?

NPV_{10} TO TRANSCANADA FROM AKLNG PROJECT



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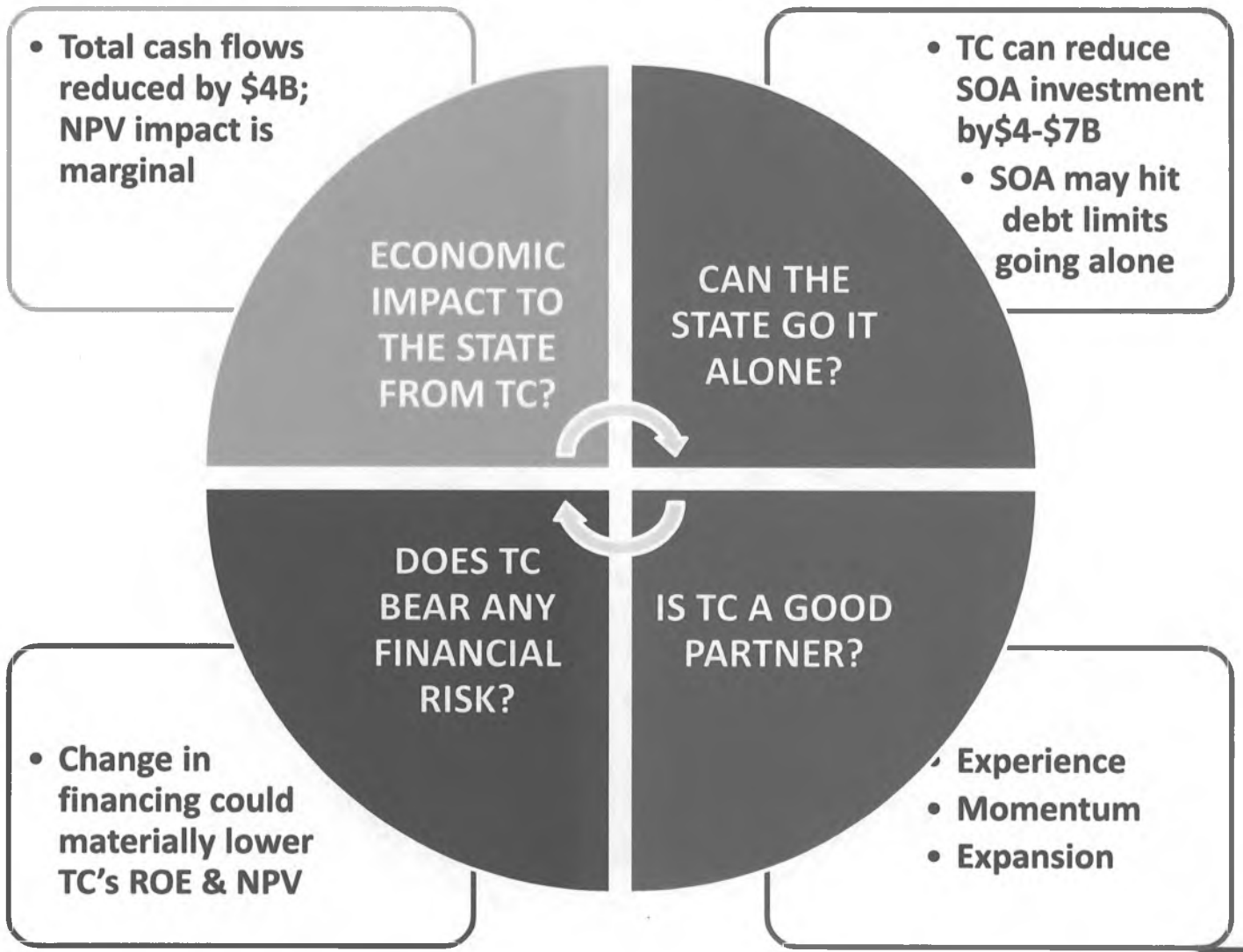
SUMMARY ON 4 KEY QUESTIONS



THANK YOU

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MARCH 25, 2014

OBSERVATIONS ON HEADS OF AGREEMENT

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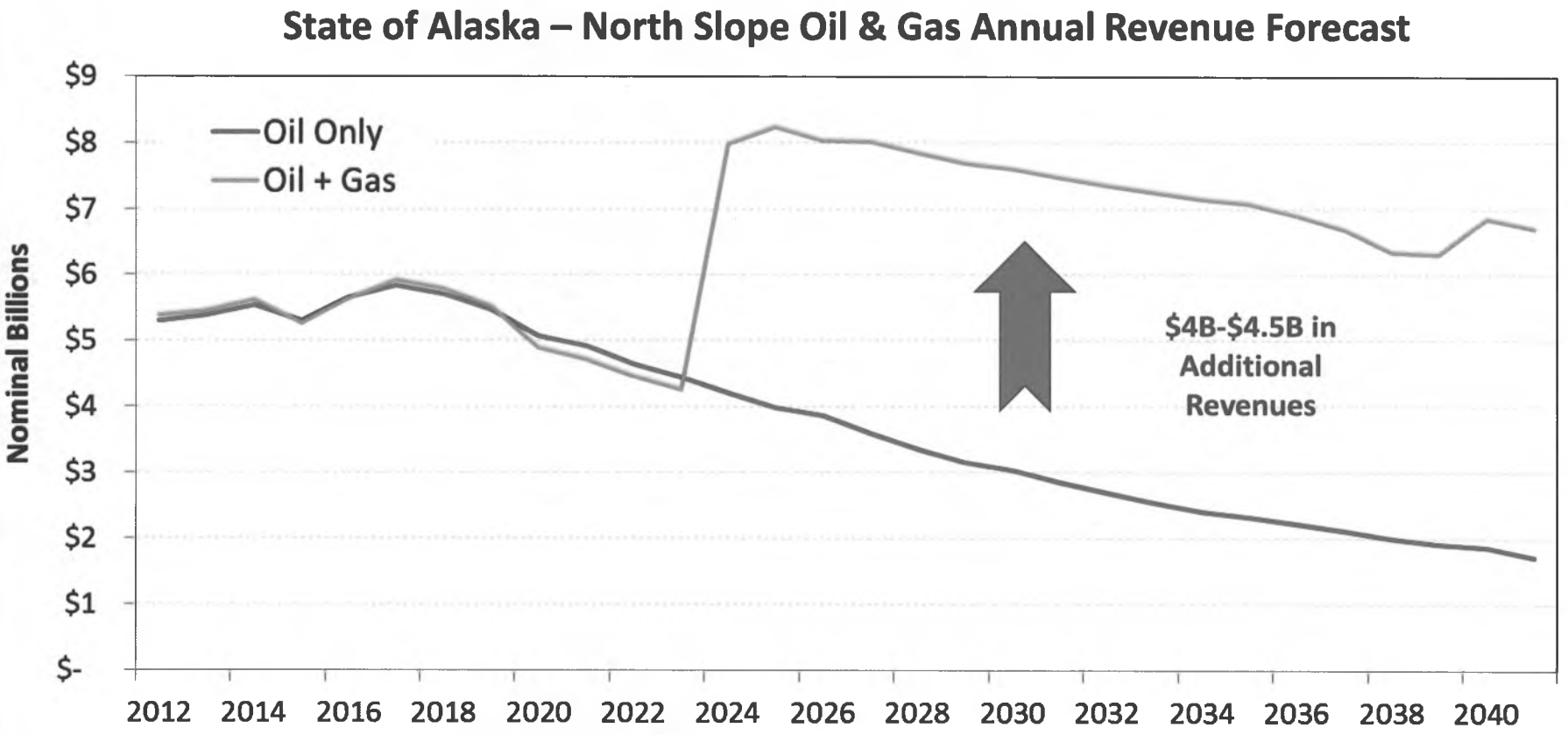
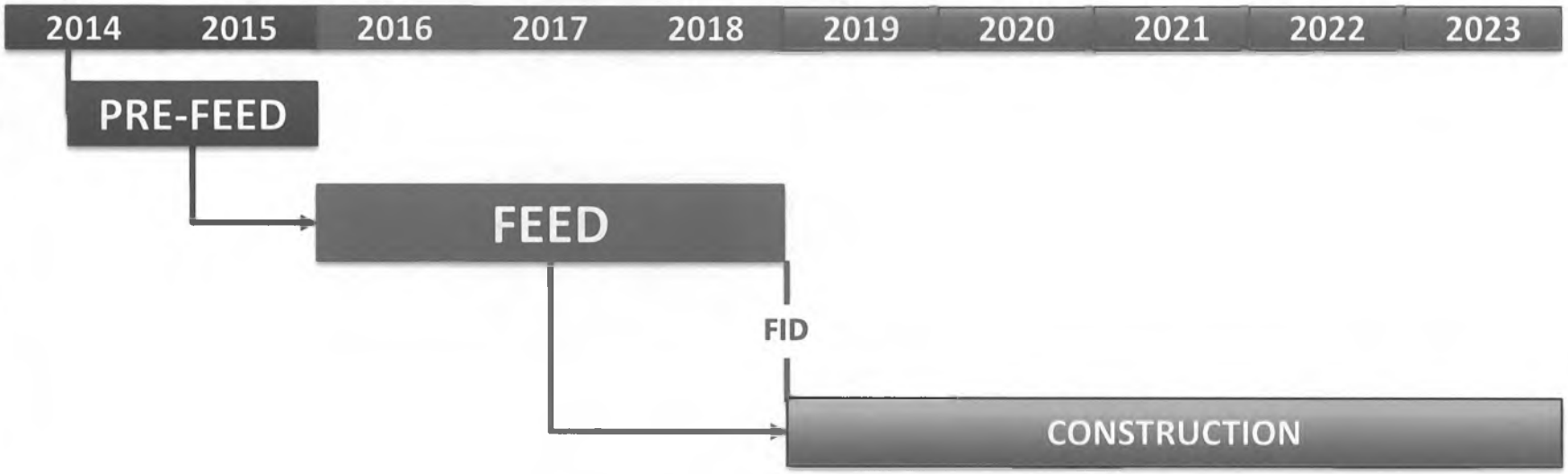
LONG-TERM NORTH SLOPE OIL & GAS REVENUES ARE DRIVEN BY AKLNG PROJECT SUCCESS



PUTTING THE HOA WITHIN THE CONTEXT OF AKLNG TIMELINE

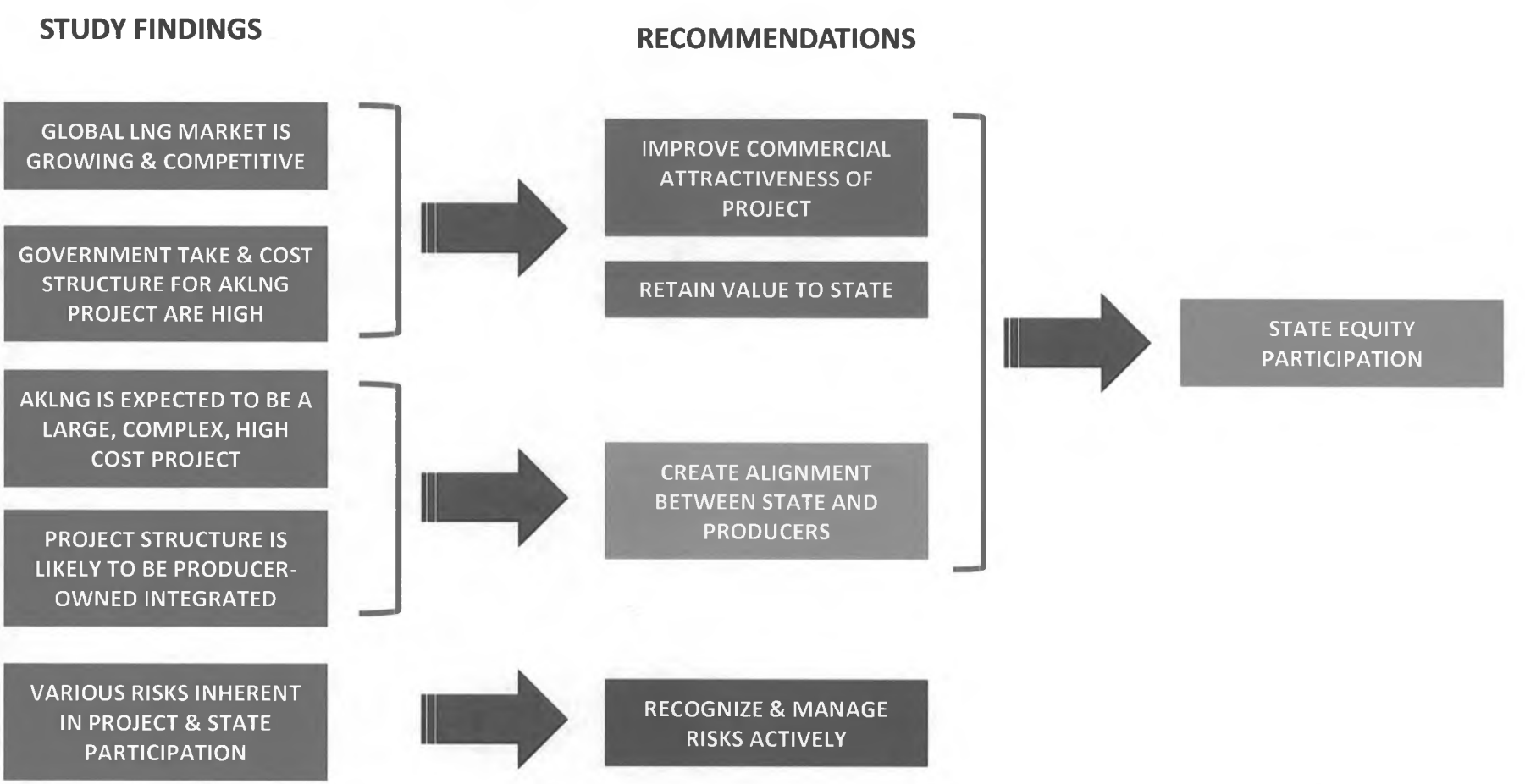


STATE INVESTMENT

$43 - $108 million or ~1% of Total Investment	**$180 - $450 million or ~2%-3% of Total Investment**	**$7 - $13 billion or ~95%-97% of Total Investment**

HOA lays out principles to advance the project to pre-FEED and enter into commercial agreements

ROYALTY STUDY HIGHLIGHTS & RECOMMENDATIONS



CRITERIA APPLIED FOR EVALUATION OF HOA TIE IN TO ROYALTY STUDY RECOMMENDATIONS

HOA – ALIGNMENT THROUGH EQUITY PARTICIPATION

ALIGNMENT

Royalty Gas and Tax as Gas = State Gas Share

State Gas Share = State Equity Share

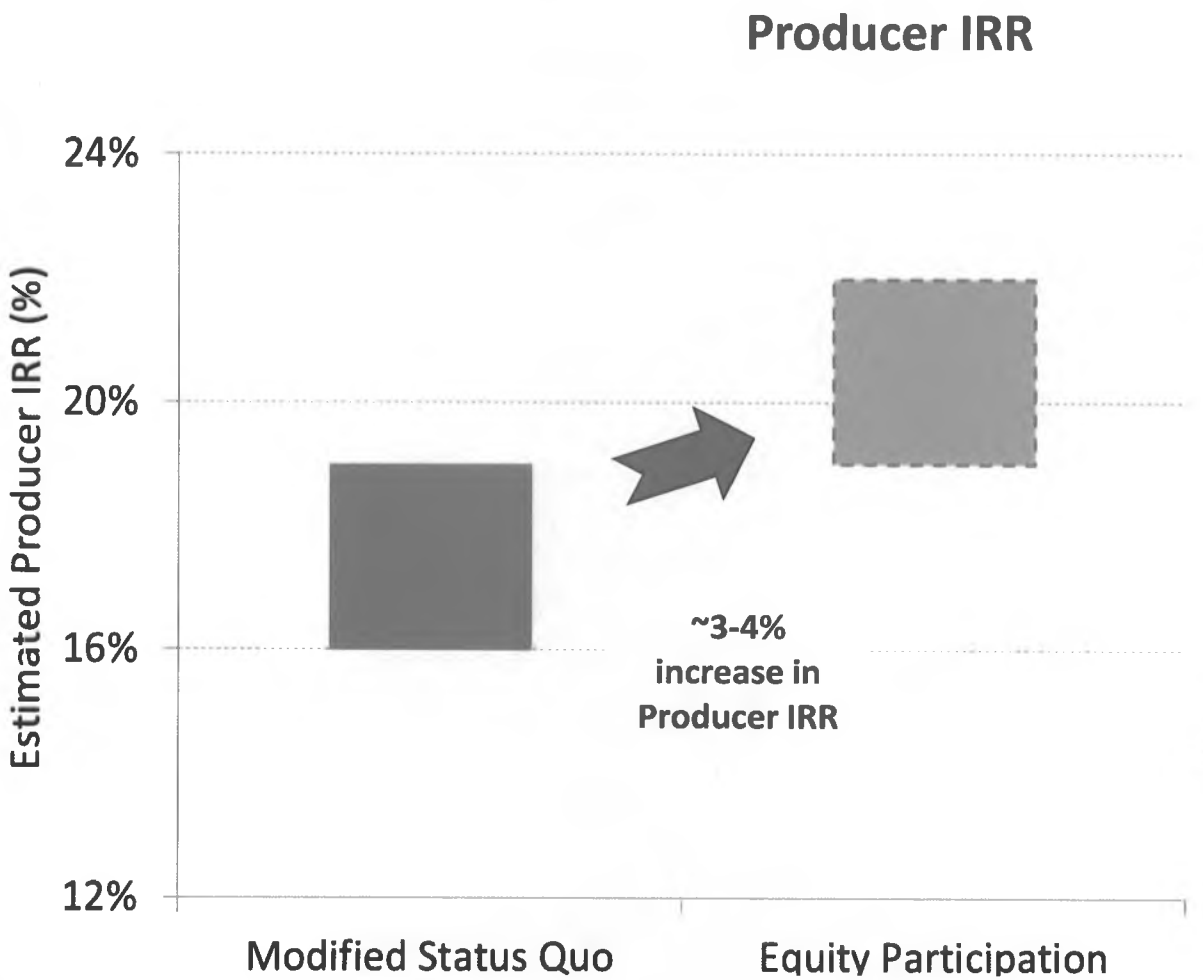
State Equity Share Impacts State Investment and State Revenues

State Holds Equity Along The Entire Supply Chain

Commitments Made In A Stage-Gated Manner

- Current decisions focused on enabling pre-FEED

IMPROVE COMMERCIAL ATTRACTIVENESS OF AKLNG PROJECT



- Reduces upfront investment by Producers
- Risk is shared with the State
- Potentially reduces valuation disputes if State elects RIK

* This analysis assumes a modified status quo wherein the production credits in SB21 are extended to reflect a $5/BOE credit for gas, similar to the credit extended to new oil production

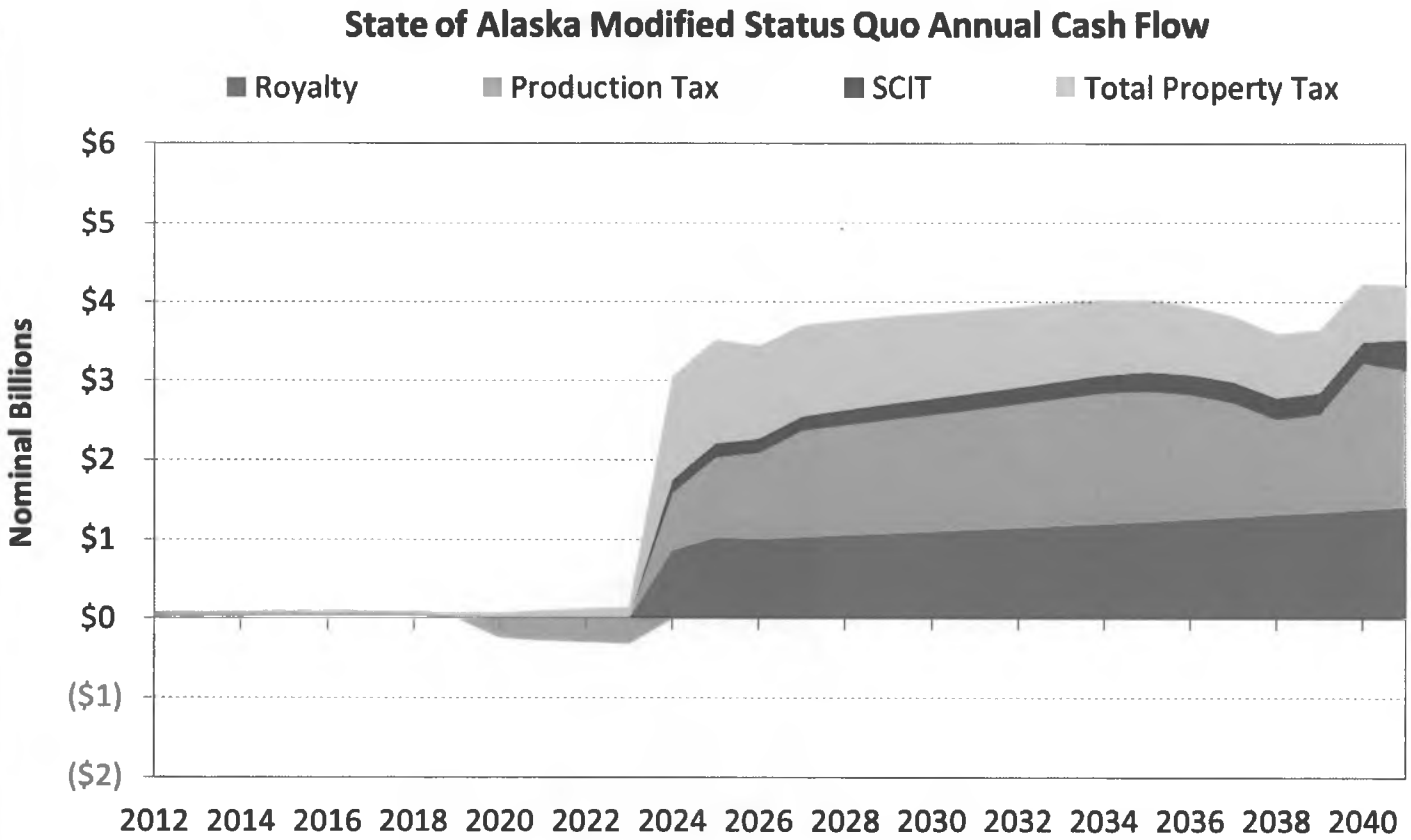
* Assumes 25% State equity participation

PRESERVE VALUE TO STATE FROM ROYALTY & TAXES

- **Obtain value in return for the State's incentives to the project**

- **Preserve the State's expected revenues from the AKLNG Project relative to an RIV world without State equity participation**

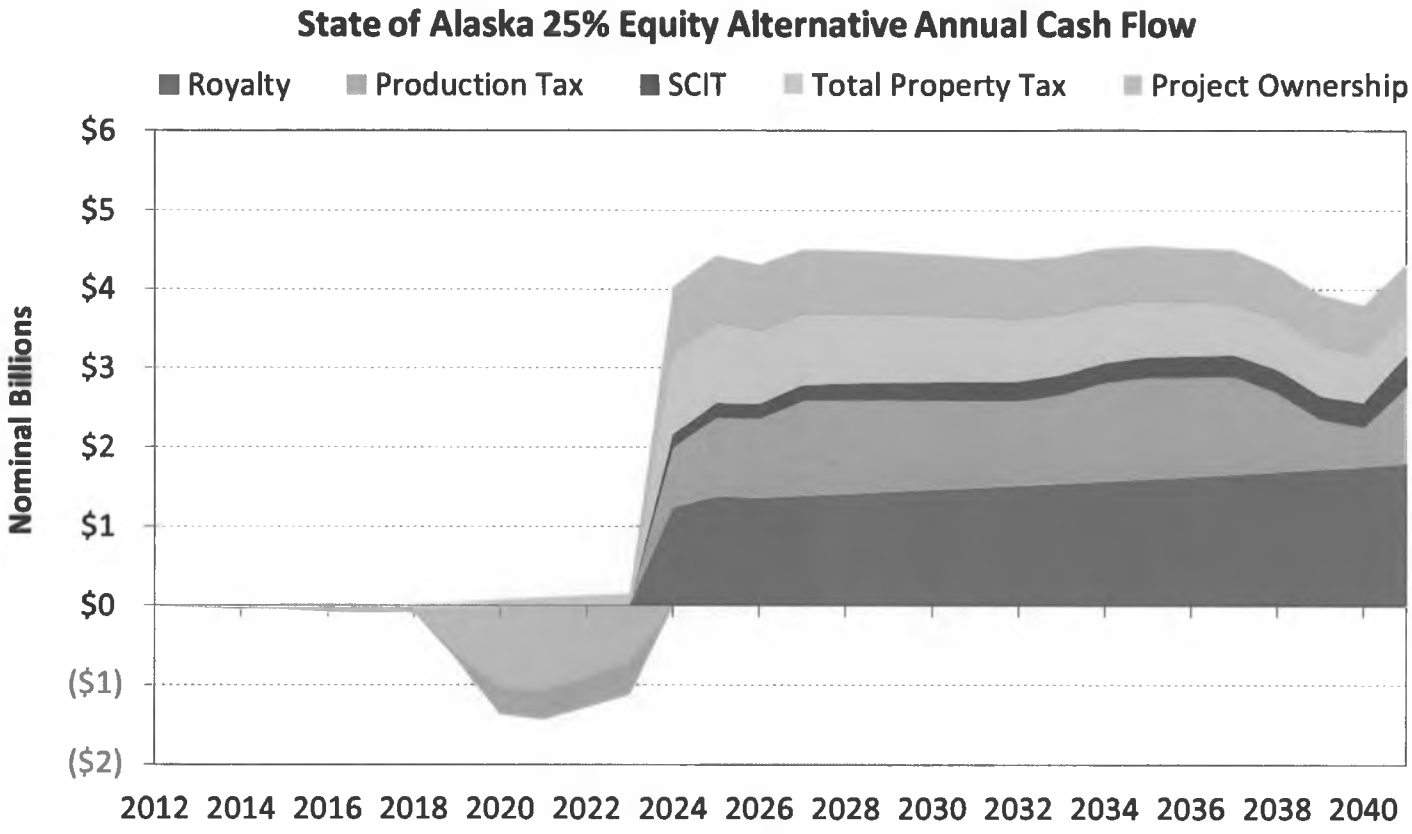
PRESERVE VALUE TO STATE FROM ROYALTY & TAXES

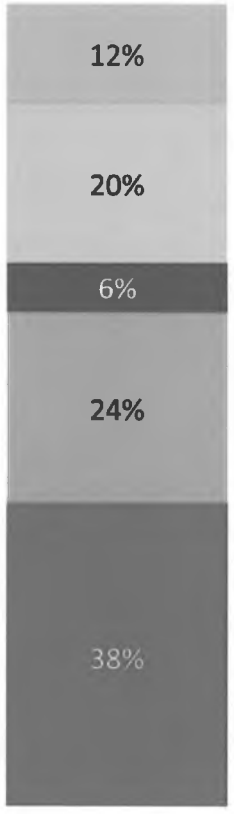


- SCIT = State Corporate Income Tax

Total Cash Flow (Through 2041) = $68 Billion

PRESERVE VALUE TO STATE FROM ROYALTY & TAXES



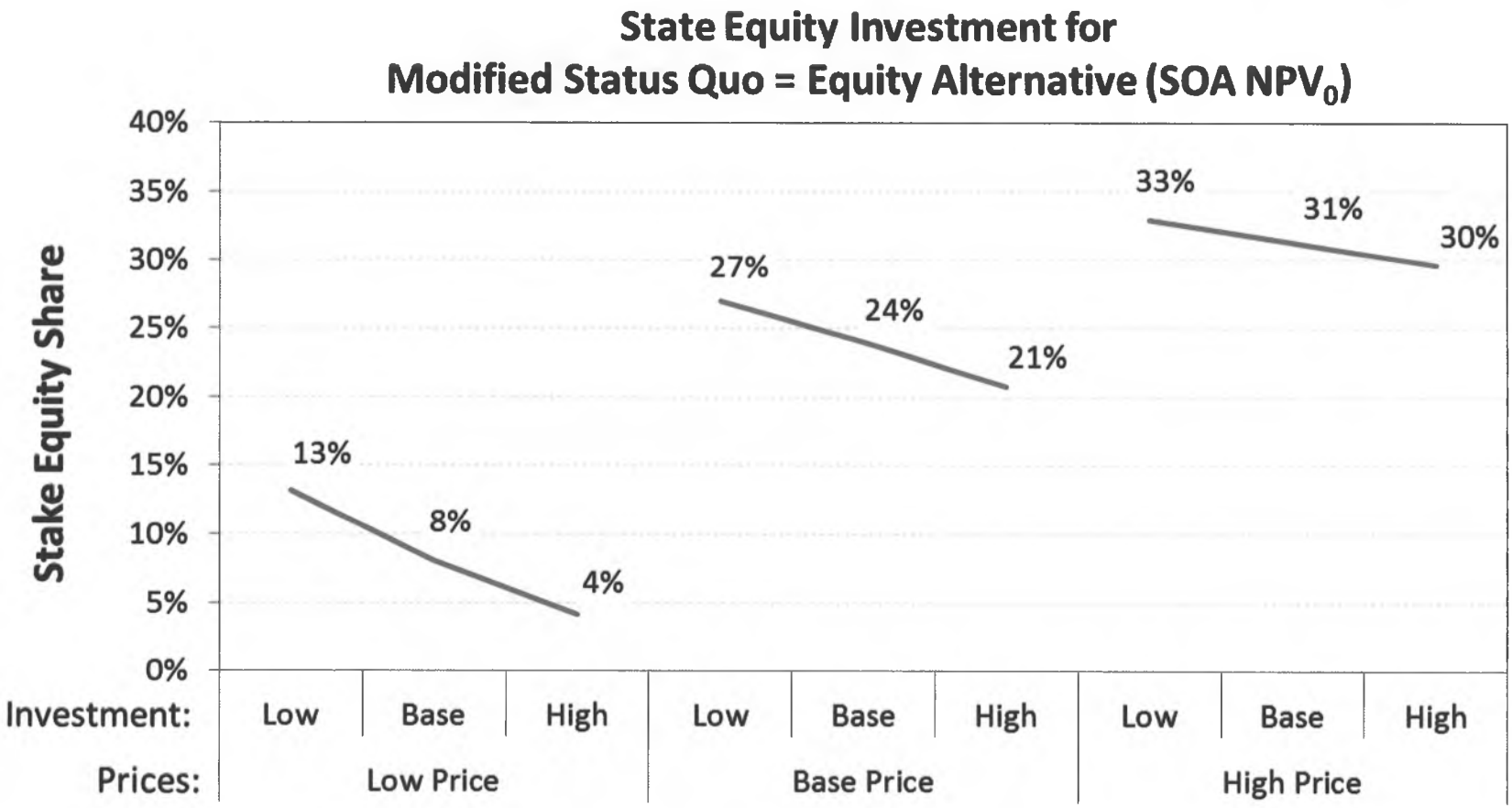


- SCIT = State Corporate Income Tax
- Project Ownership = Return on the equity that the State invests in the AKLNG project

Total Cash Flow (Through 2041) = $72 Billion

PRESERVE VALUE TO STATE FROM ROYALTY & TAXES

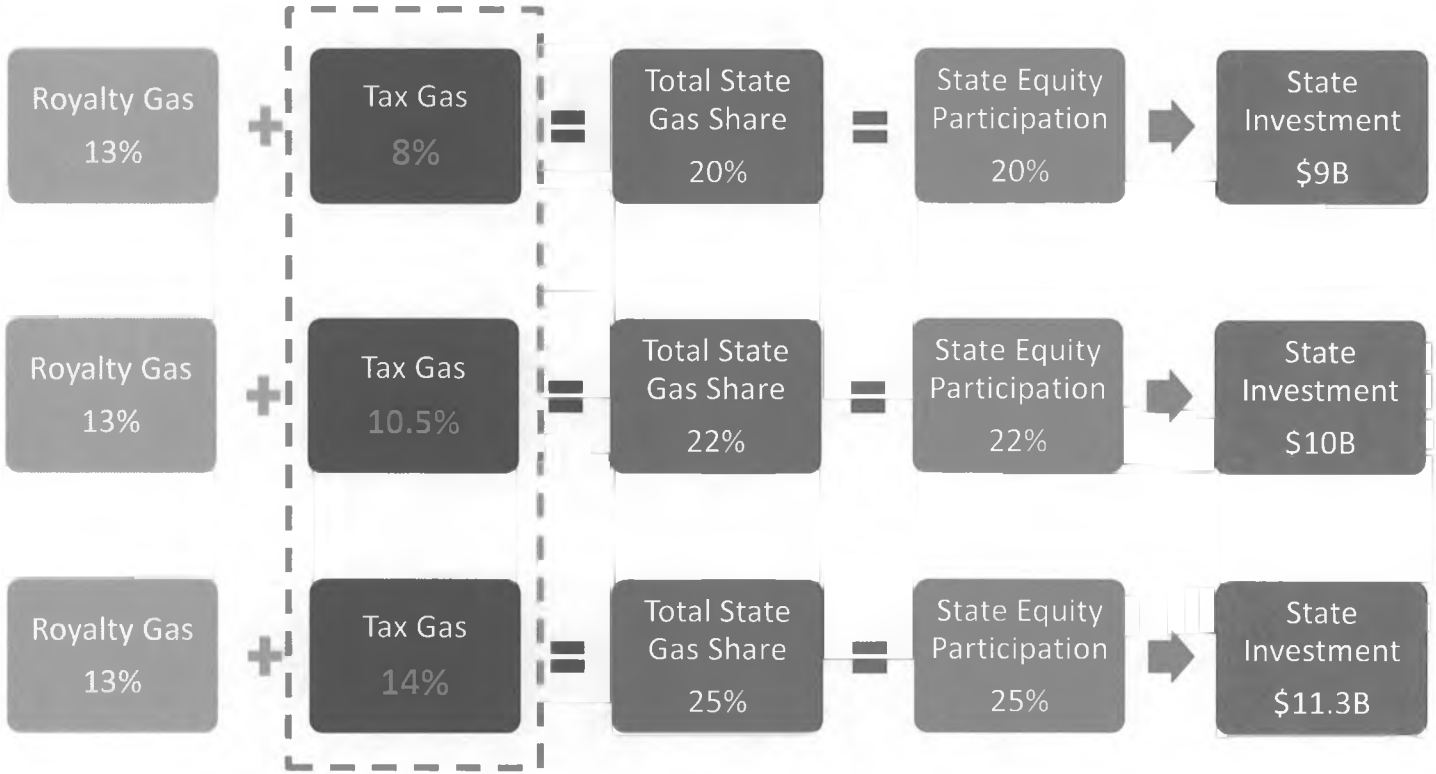
VALUE TO SOA



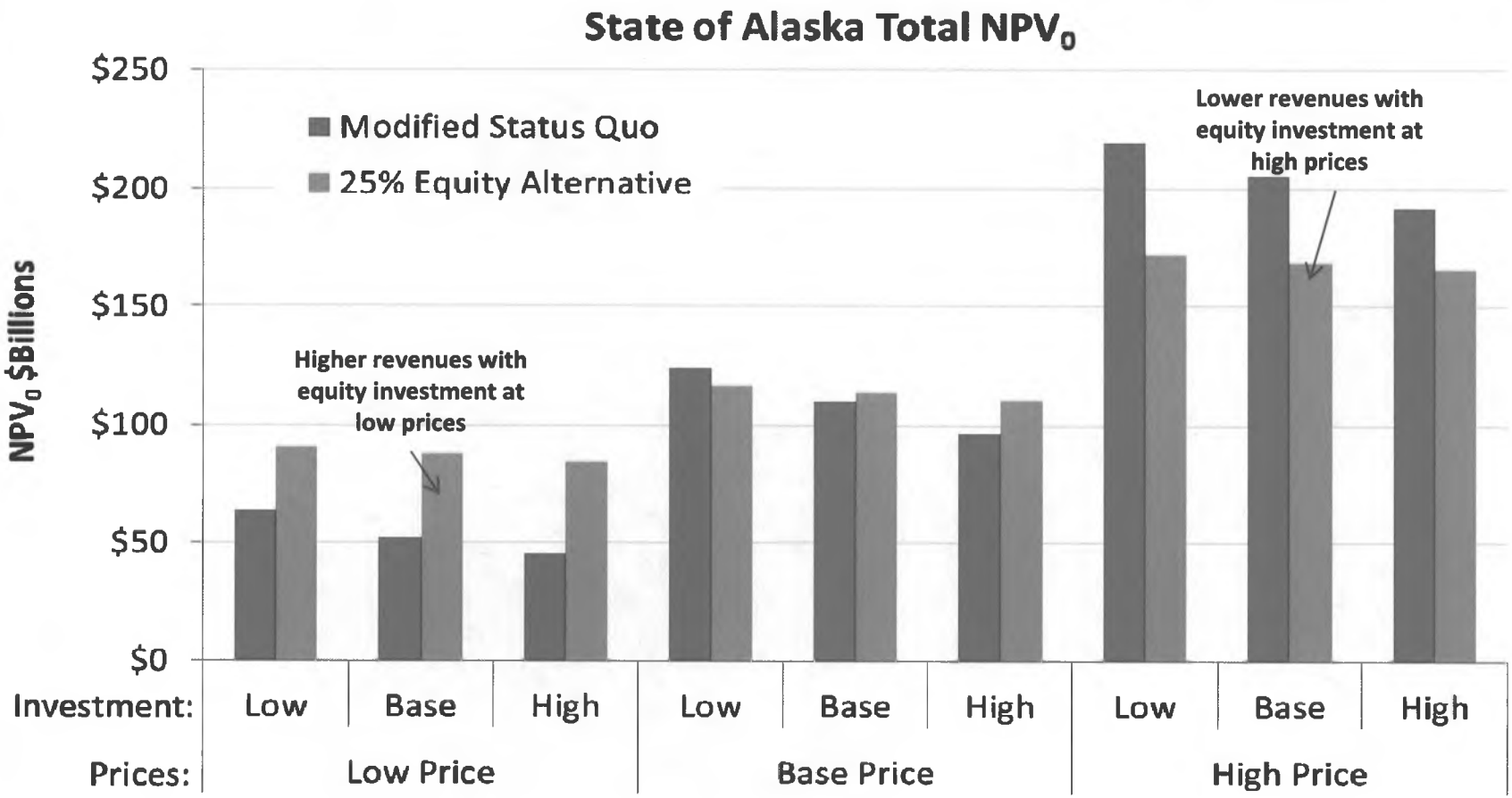
* This analysis assumes a modified status quo wherein the production credits in SB21 are extended to reflect a $5/BOE credit for gas, similar to the credit extended to new oil production

GROSS TAX RATE SETS THE TOTAL STATE GAS SHARE & EQUITY PARTICIPATION

VALUE TO SOA



MANAGE RISKS – EQUITY INVESTMENT HELPS TO HEDGE PRICE EXPOSURE



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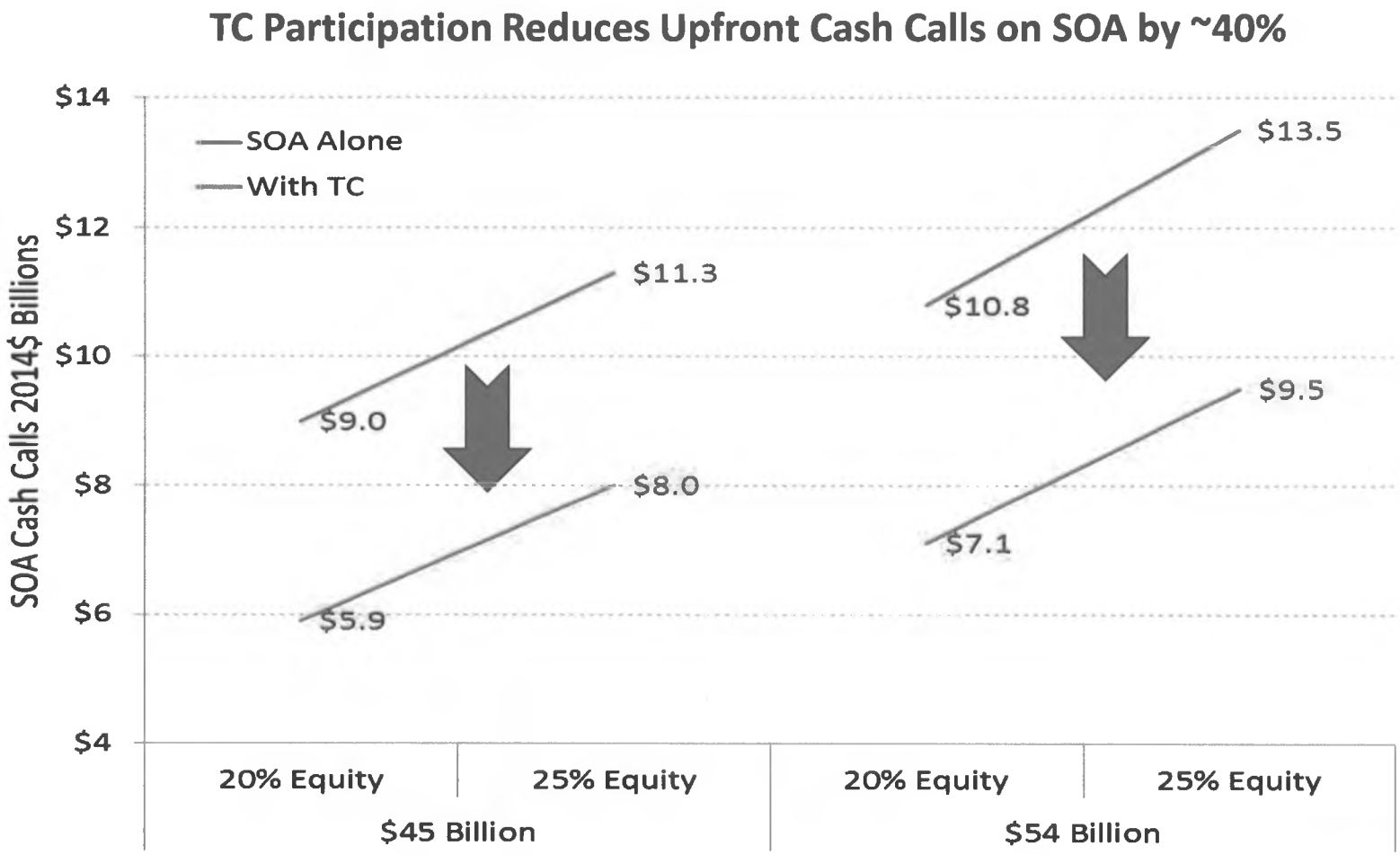


* Assumes State exercises 30%-40% equity buy back with TransCanada

MANAGE RISKS – REDUCE POTENTIAL LOSS OF VALUE THROUGH RIK

RIK MARKETING ALTERNATIVES

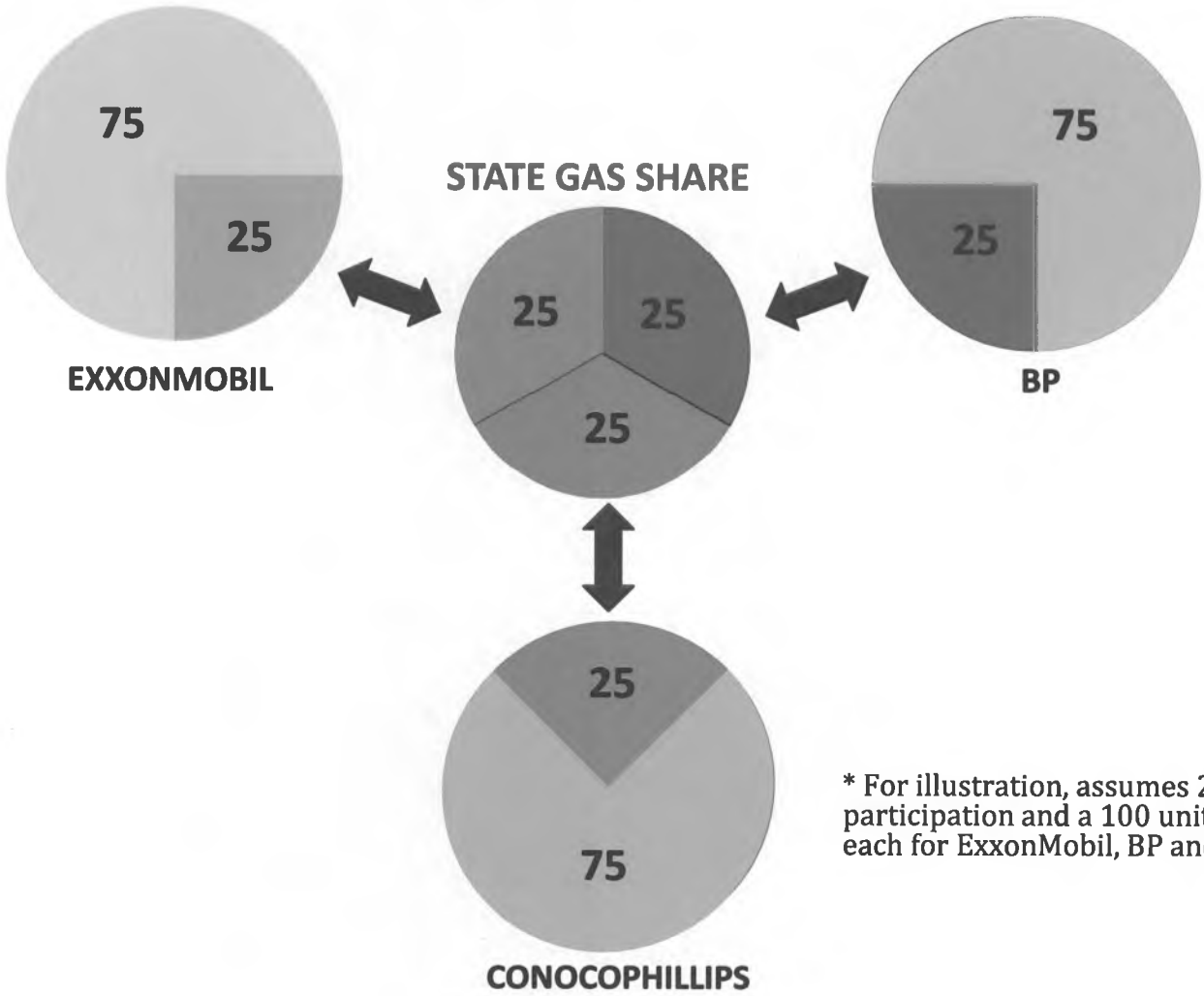
SOA MARKETS ITS OWN SHARE	• No current experience or marketing organization • Competing with Producers
3RD PARTY MARKETS STATE'S SHARE	• Discussions with 3rd parties to gauge interest and terms • Potential for upside
PRODUCERS MARKET STATE'S SHARE	• Benefit from Producer's marketing expertise • Procure terms similar to what the Producers achieve • Recreate a key advantage of RIV

MANAGE RISKS – REDUCE POTENTIAL LOSS OF VALUE THROUGH RIK

- HOA includes intent of Producers to offer to negotiate separately to market State's share of gas – proportional to each Producer's share of producer capacity
- SOA to only obligated to elect RIK if the Producers make "satisfactory arrangements for disposition of the State's share of LNG"
- SOA would benefit from Producers marketing expertise rather than competing with them

MANAGE RISKS – REDUCE POTENTIAL LOSS OF VALUE THROUGH RIK

EACH PRODUCER WOULD MARKET "ITS CONTRIBUTION" TO THE STATE GAS SHARE



* For illustration, assumes 25% State equity participation and a 100 units of production each for ExxonMobil, BP and ConocoPhillips.

MANAGE RISKS – STRUCTURE OF PARTICIPATION

HOA ELEMENTS

- PROJECT WITHIN A PROJECT
- ACCESS & PRO-EXPANSION PRINCIPLES
- STAGE-GATED COMMITMENTS
- ACCESS TO INFORMATION

→ **COMMERCIAL AGREEMENTS**

HOA SCORE CARD RELATIVE TO CRITERIA

Royalty Study Recommendations	How HOA Addresses Recommendation
Alignment Through Equity	Equity Participation Along Supply Chain; Royalty and tax as share of gas
Improve Commercial Attractiveness	Increases Producer IRR Shares/Reduces Producer Risk
Preserve Value to the State	State could be Cash Flow Neutral relative to status quo depending on final equity share
Manage Risks	
Price Exposure	Equity Participation in midstream dampens exposure to prices
Capital Costs	TC participation lowers State's cash calls prior to commercial operation
RIK Marketing	HOA reflects intent of Producers to negotiate to market State's share of gas
Structure of Participation	Project within a project, Stage gated commitments, Access & pro-expansion principles, Access to information

THANK YOU

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PROJECT STRUCTURE, FINANCE, CASH FLOWS AND MIDSTREAM

Prepared for House Resources Committee
Juneau, Alaska › March 24, 2014

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

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Nikos Tsafos has a diverse background in the private, public and non-profit sectors. He is currently a founding partner at *en*alytica. In his 7 ½ years with PFC Energy, Nikos 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).

EXECUTIVE SUMMARY

Several ways to structure an LNG project, but existing structure has lots of merit

Financing plan yet to be determined–but state has lots of options

Stress case scenario yields lower returns, but only in extreme case, negative cash flow

MOU makes sense financially if the state is assumed to be capital constrained

TransCanada tariff is expensive vis-a-vis state's cost of debt, but attractive relative to market norms

TransCanada's share of cash flows ranges from 1% to 7% of total (depending on price and 'buyback')

Finer points of MOU–related to risk allocation–worth focusing on

PROPOSED PROJECT STRUCTURE HAS LOTS OF MERIT

Possible Project Structures based on Ownership

Upstream	Gas Treatment	Pipeline	Liquefaction
Oil companies; SOA royalty and taxes	Oil companies own 100%	Oil companies own 100%	Oil companies own 100%
Oil companies; SOA becomes partner	Oil companies + SOA	Oil companies + SOA	Oil companies + SOA
No oil companies; SOA fully acquires upstream	Oil companies + SOA + 3rd party	Oil companies + SOA + 3rd party	Oil companies + SOA + 3rd party
	Oil companies + 3rd party	Oil companies + 3rd party	Oil companies + 3rd party
	SOA 100%	SOA 100%	SOA 100%
	SOA + 3rd party	SOA + 3rd party	SOA + 3rd party
	3rd party 100%	3rd party 100%	3rd party 100%

in dark grey boxes: project structure as envisioned by the HOA and MOU

VARIOUS FINANCING OPTIONS OPEN TO LNG PROJECTS

Balance Sheet Finance

Project sponsors provide funds

Funds can combine debt and cash flow

Guaranteed by project sponsor (recourse)

Rate depends on sponsor's balance sheet

Easier if all parties have strong balance sheets

Project Finance

Third parties lend to project directly, not to sponsors

Sponsors put up some equity (e.g. 30%)

Guaranteed by projected revenues (non-recourse)

Rate depends on project risk

Easier to accommodate riskier sponsors

Key Questions for State of Alaska

What mix of debt and equity?

Will debt be specific to LNG project, or broader state balance sheet liability?

Will equity come from recurrent revenues, or other sources?

What role does the permanent fund play and how does this affect restricted / unrestricted revenue?

PROJECT FINANCE WELL ESTABLISHED IN LNG

IHS estimates that LNG projects raised over $97 billion in third-party financing since 2000

Financing from project sponsors, export credit agencies, multilateral banks and commercial banks

Commercial loans can also secure sovereign guarantees as insurance

The Japan Bank of International Cooperation (JBIC) is the largest single provider of funds

Examples

Australia Pacific LNG	$5.8 billion	US EXIM, China EXIM, banks
Ichthys	$20 billion	JBIC, Korea and Australia EXIM, banks, sponsors ($4 bn)
Papua New Guinea	$14 billion	Six ECAs and 17 banks, ExxonMobil
Peru	$2.25 billion	IADB, US EXIM, Korea EXIM, IFC, others
Sakhalin-2	$6.4 billion	JBIC, NEXI, banks
Tangguh	$3.5 billion	JBIC, ADB, banks

Project ownership cash flows

(+) revenue = volume x price

(-) capital expenditures

(-) operations and maintenance expenses

(-) debt service (principal and interest)

(-) tariff paid to TransCanada

Cash flows from sovereign functions

(+) state income tax

(+) property tax

Four cash flow scenarios

No debt and no TransCanada partnership

No TransCanada partnership but the state finances 70% of its share with debt

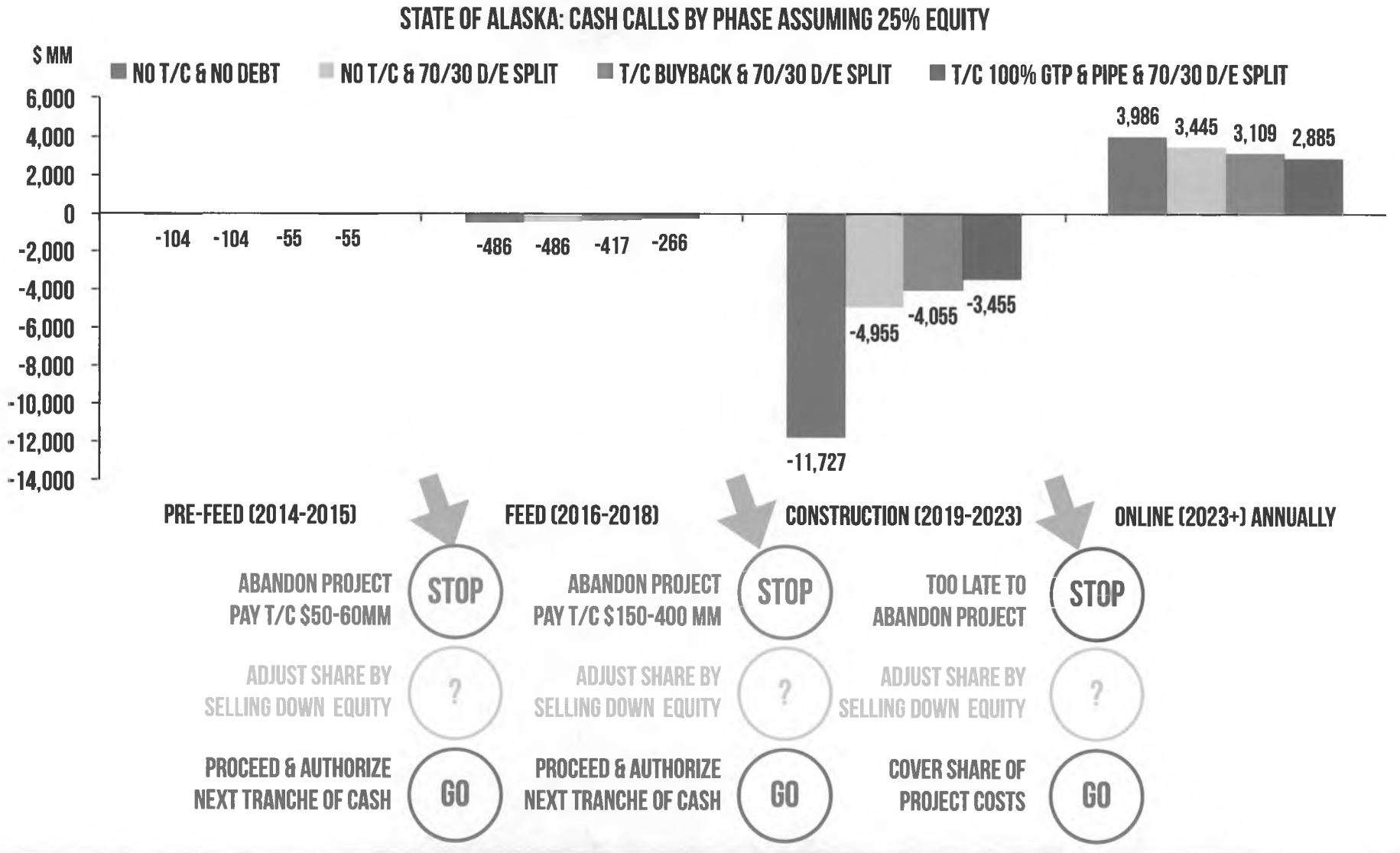
TransCanada is a partner and the state exercises its buyback option

TransCanada is a partner and the state does not exercise its buyback option

To understand unrestricted flows to the treasury, we can re-arrange the cash flows in a different way:

State unrestricted = total cash flows – permanent fund (25% of royalty) – property tax

SOA'S CASH CALLS AND OFF-RAMPS



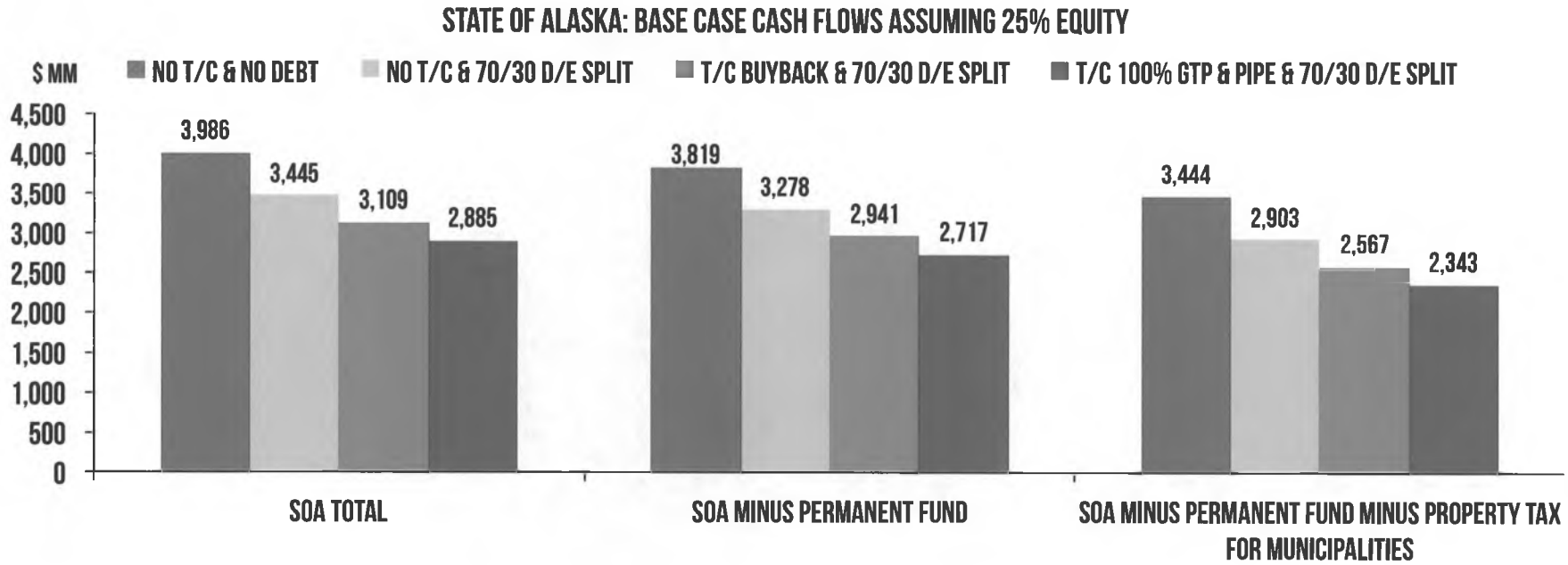
LNG INCOME INCLUDES RESTRICTED REVENUE

Revenue

Total income

Total income minus permanent fund (25% of royalty)

Total income minus permanent fund and property taxes allocated to municipalities

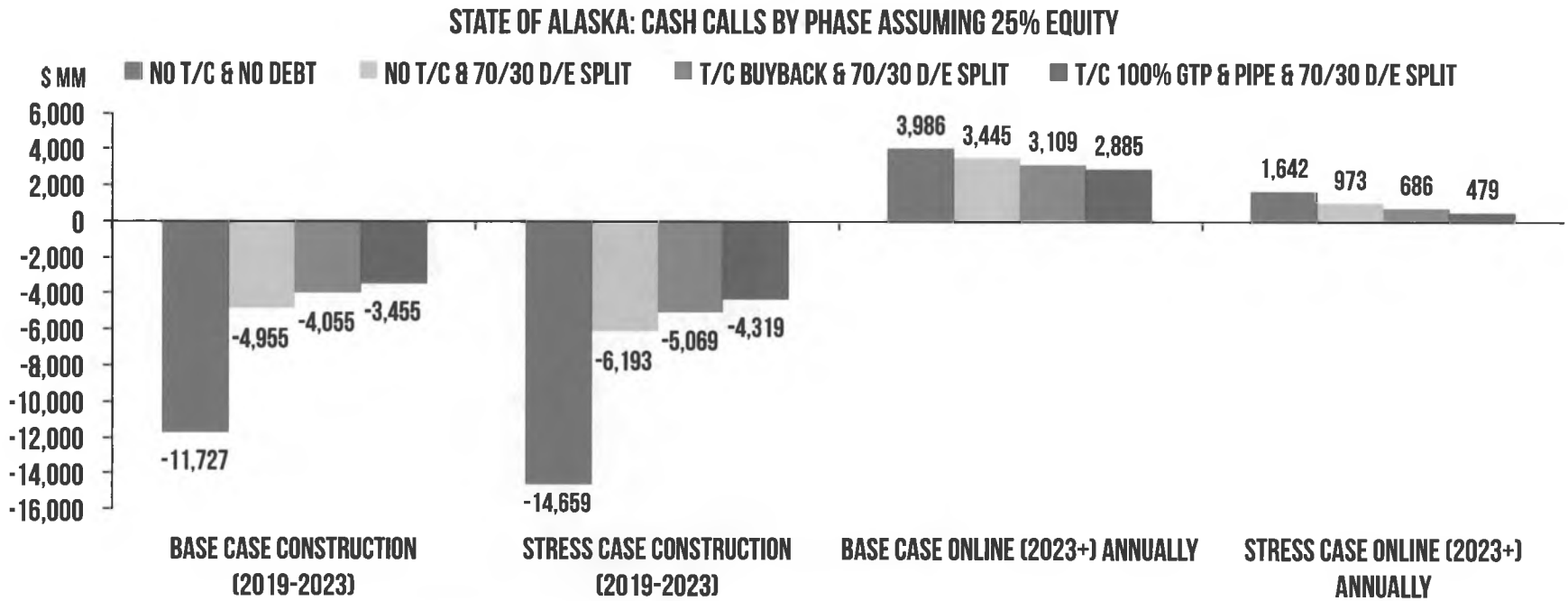


STRESS TESTING SOA'S CASH CALLS AND REVENUES

Stress Test Project CAPEX is 25% higher

+ Sales price is $7/mmbtu vs. $15/mmbtu in base case

+ Average utilization (output ÷ capacity) is 80% vs. 100% in base case



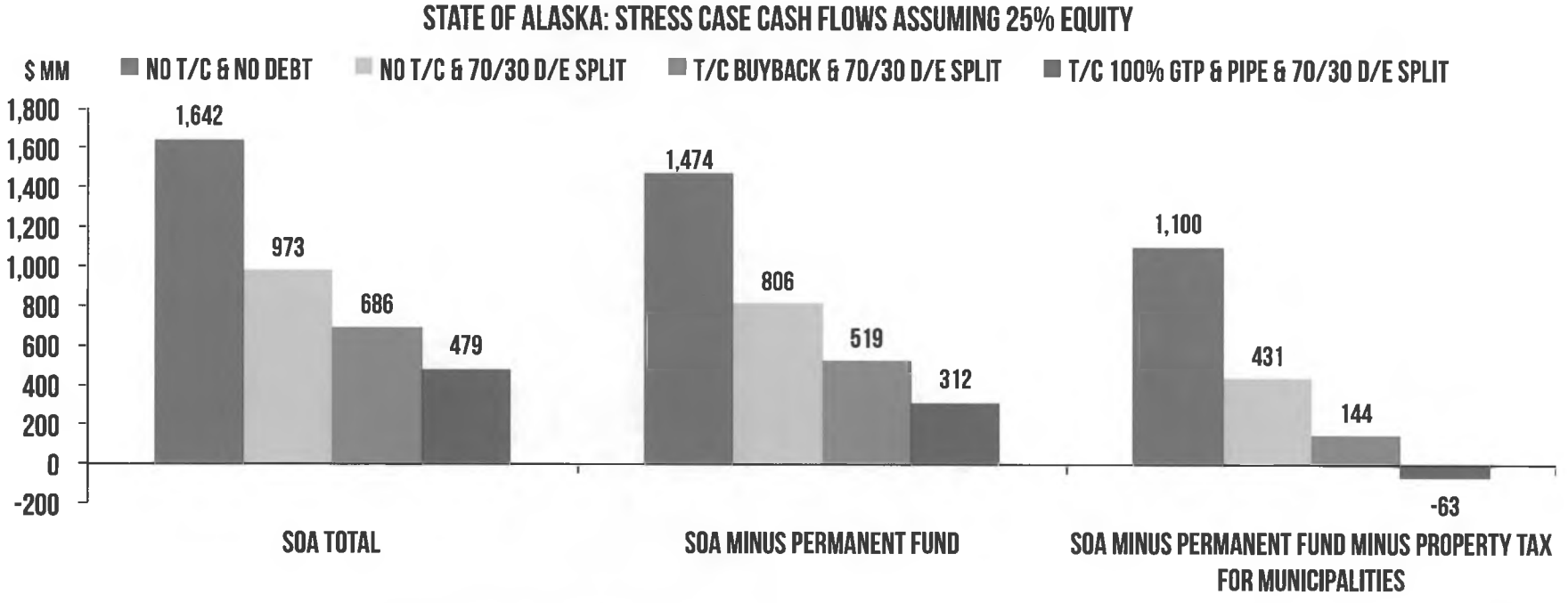
STRESS TEST: RESTRICTED VS. UNRESTRICTED REVENUES

Revenue

Total income

Total income minus permanent fund (25% of royalty)

Total income minus permanent fund and property taxes allocated to municipalities



SOA NEEDS TO CAREFULLY WEIGH KEY QUESTIONS

What compensation might the SOA have to pay and what intellectual property will Alaska LNG retain?

Will the HOA process slow down if the midstream is tied in litigation?

What are the odds that a new selection process will deliver better terms than those available today?

To what extent was the AGIA process representative of the industry's interest in an Alaskan pipeline?

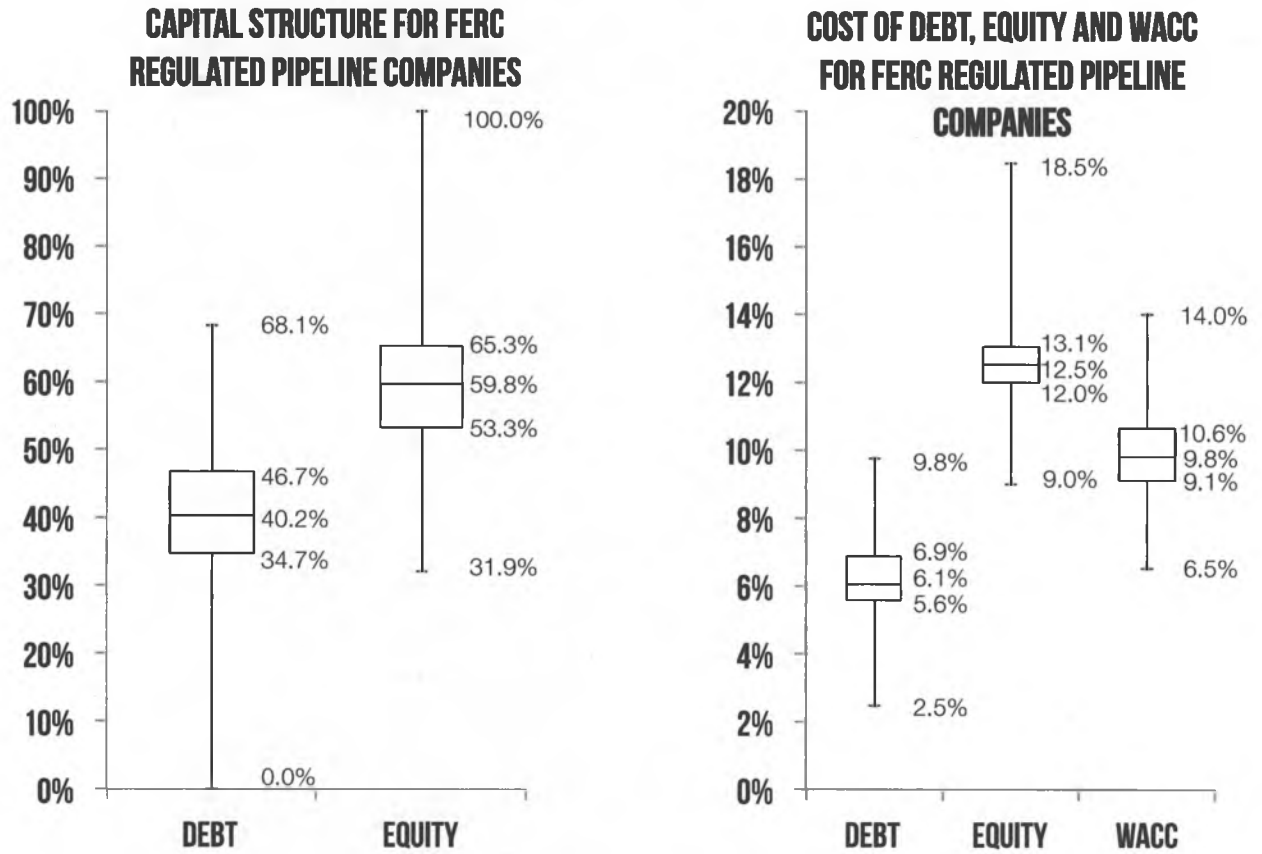
Would a new tariff offset absence from negotiating table; reduced momentum; cost to dissolve AGIA?

	PRODUCERS	PRODUCERS + STATE OF ALASKA	PRODUCERS + STATE OF ALASKA + TRANSCANADA	PRODUCERS + STATE OF ALASKA + 3RD PARTY
PRODUCER-SOA ALIGNMENT	✗	✓	✓	✓/?
THIRD-PARTY EXPANSION	✗	?	✓✓	✓
IN-STATE DELIVERIES	✗	✓	✓✓	✓✓
EXECUTION	✓	✓/?	✓	✓
CONTINUITY & MOMENTUM	?	?	✓	✗

TRANSCANADA TARIFF OFFER WITHIN MARKET NORMS

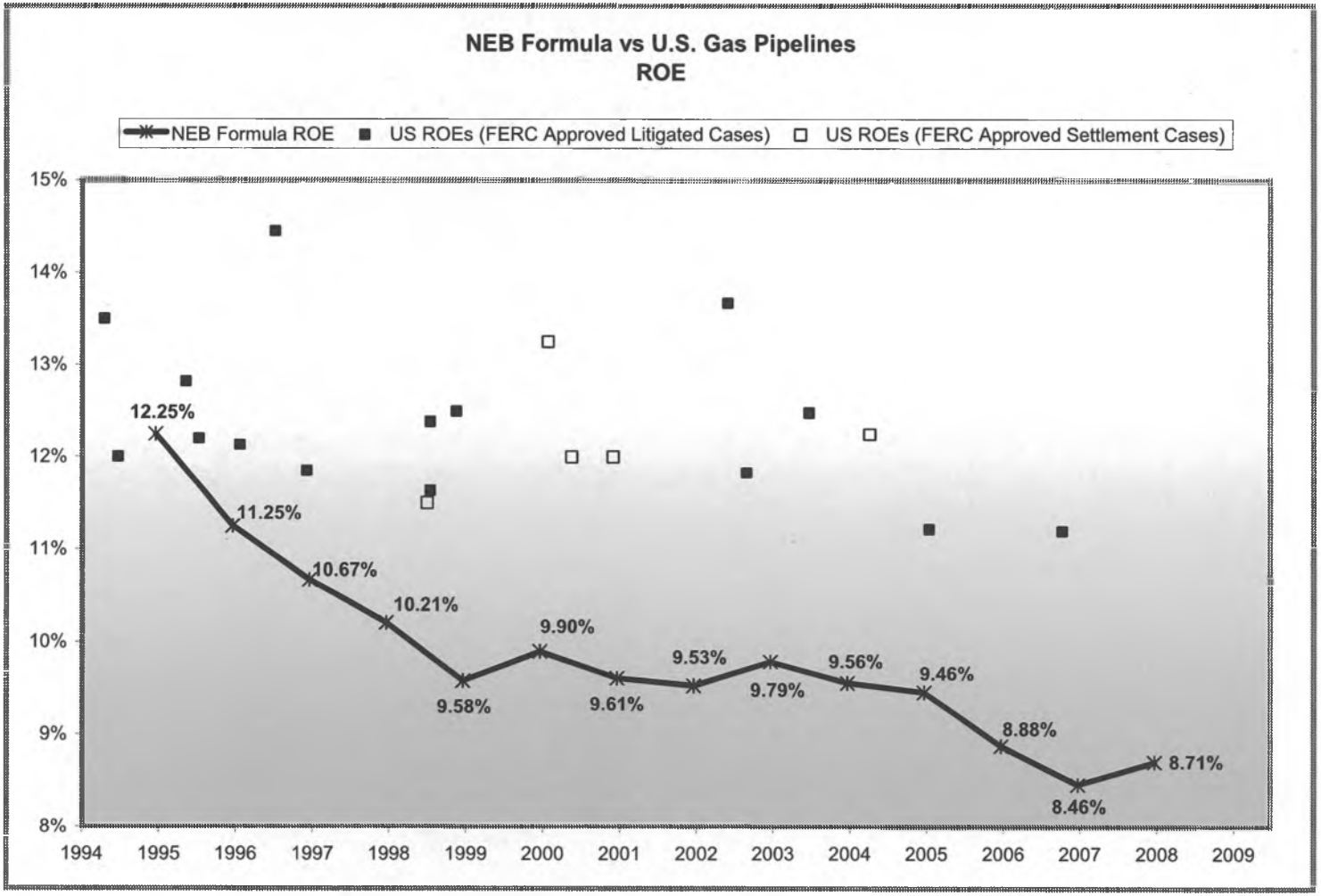
Capitalization structure (75:25 debt:equity) is more weighted toward debt than average FERC pipeline

Cost of equity (12%) and debt (5%) below average; weighted cost of capital (6.75%) near bottom of group



SOURCES: ENALYTICA BASED ON "FORM 2/2A - MAJOR AND NON-MAJOR NATURAL GAS PIPELINE ANNUAL REPORT," 2012

FERC ROE HISTORICALLY EXCEED NEB (CANADA) ROE



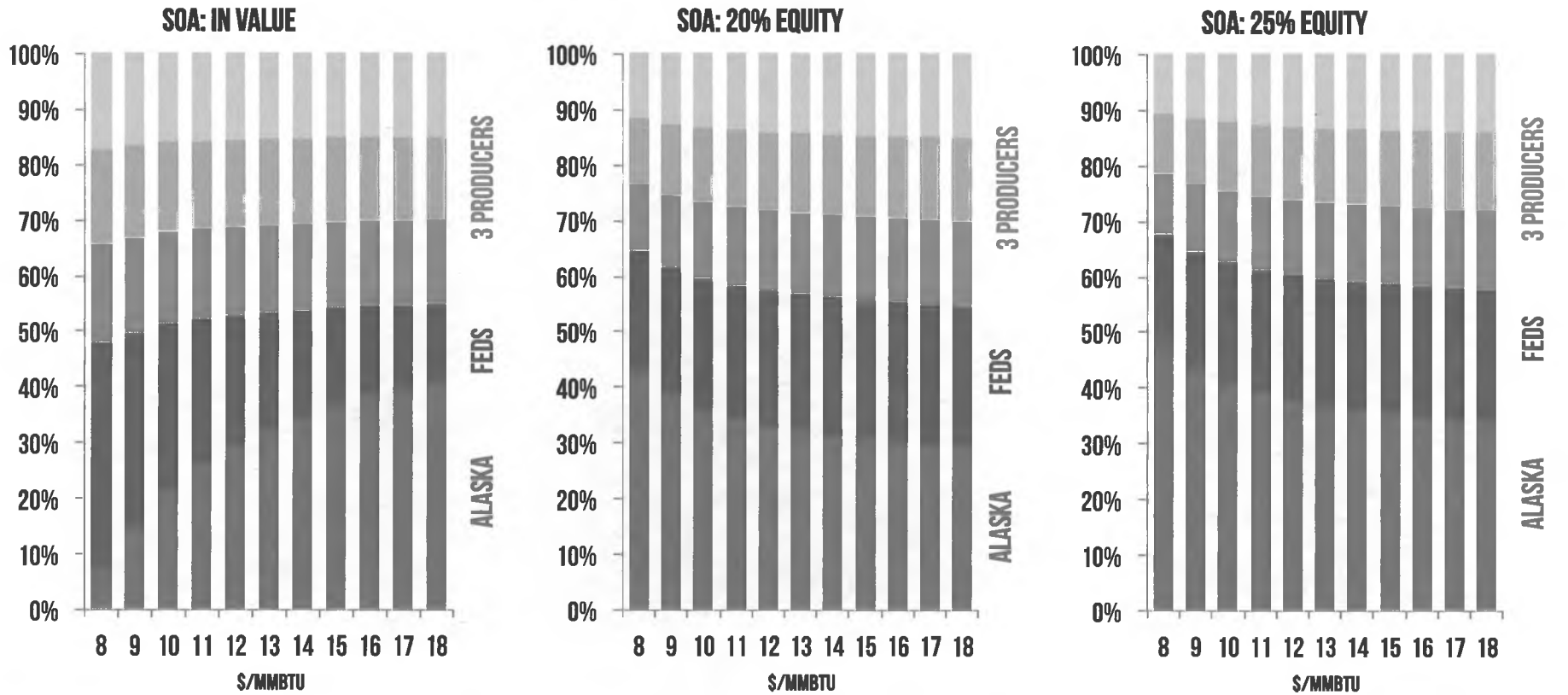
SOURCES: CANADIAN ENERGY PIPELINE ASSOCIATION (CEPA), PERSPECTIVE ON CANADIAN GAS PIPELINE ROES, FEBRUARY 2008

SOA EQUITY LEADS TO HIGHER GOV'T TAKE ON AVERAGE

'In value' entails lowest government take, especially in low prices as cash goes to producers

Split between Fed vs. SOA split depends on both 'in value' vs. 'in kind' as well as SOA equity share

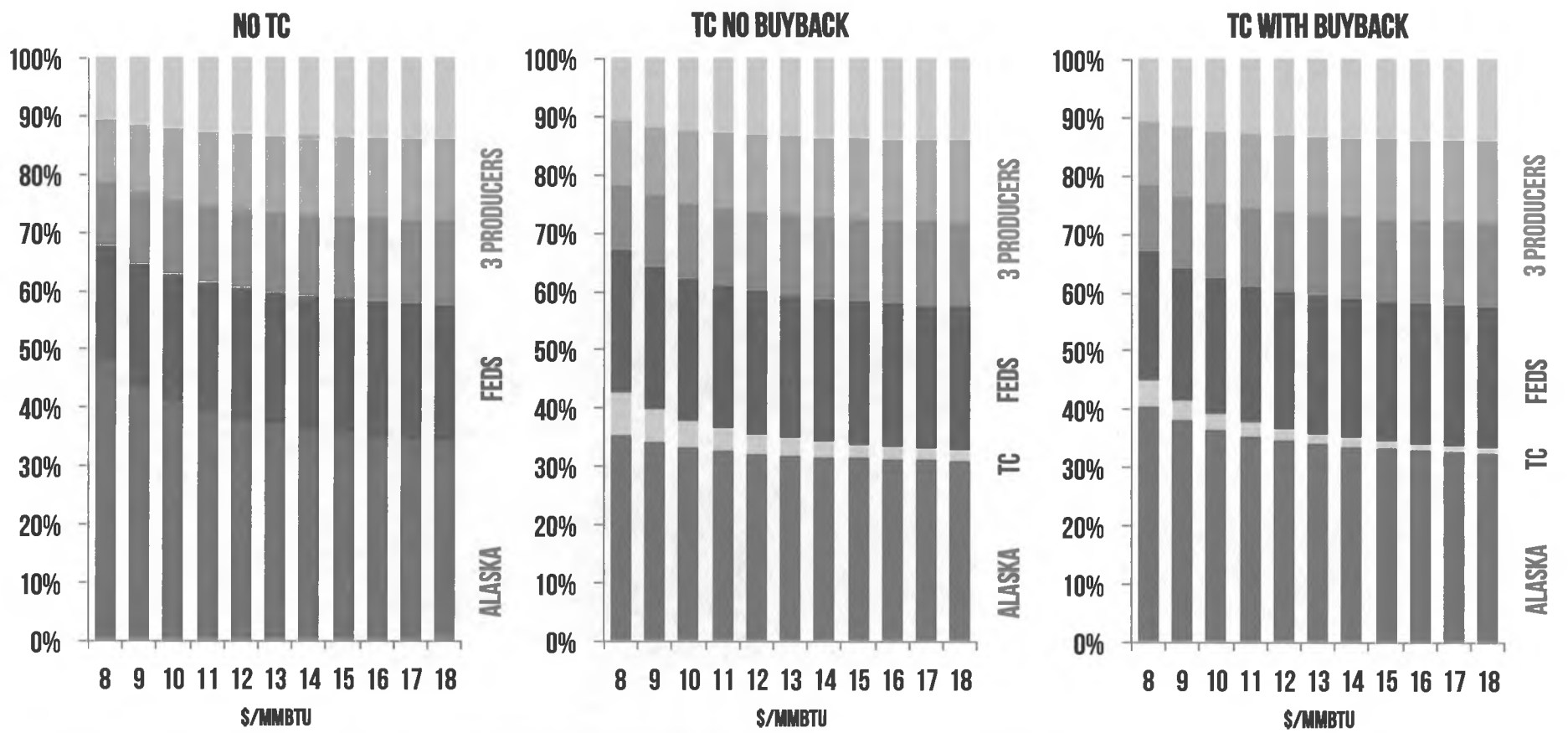
PERCENT OF CUMULATIVE CASH FLOWS OVER PROJECT LIFE



TC'S SHARE OF CASH IS HIGHEST AT LOW PRICES

TC's share ranges from 1% to 7%, depending on price levels and state's exercise of buyback

PERCENT OF CUMULATIVE CASH FLOWS OVER PROJECT LIFE, 25% EQUITY CASE

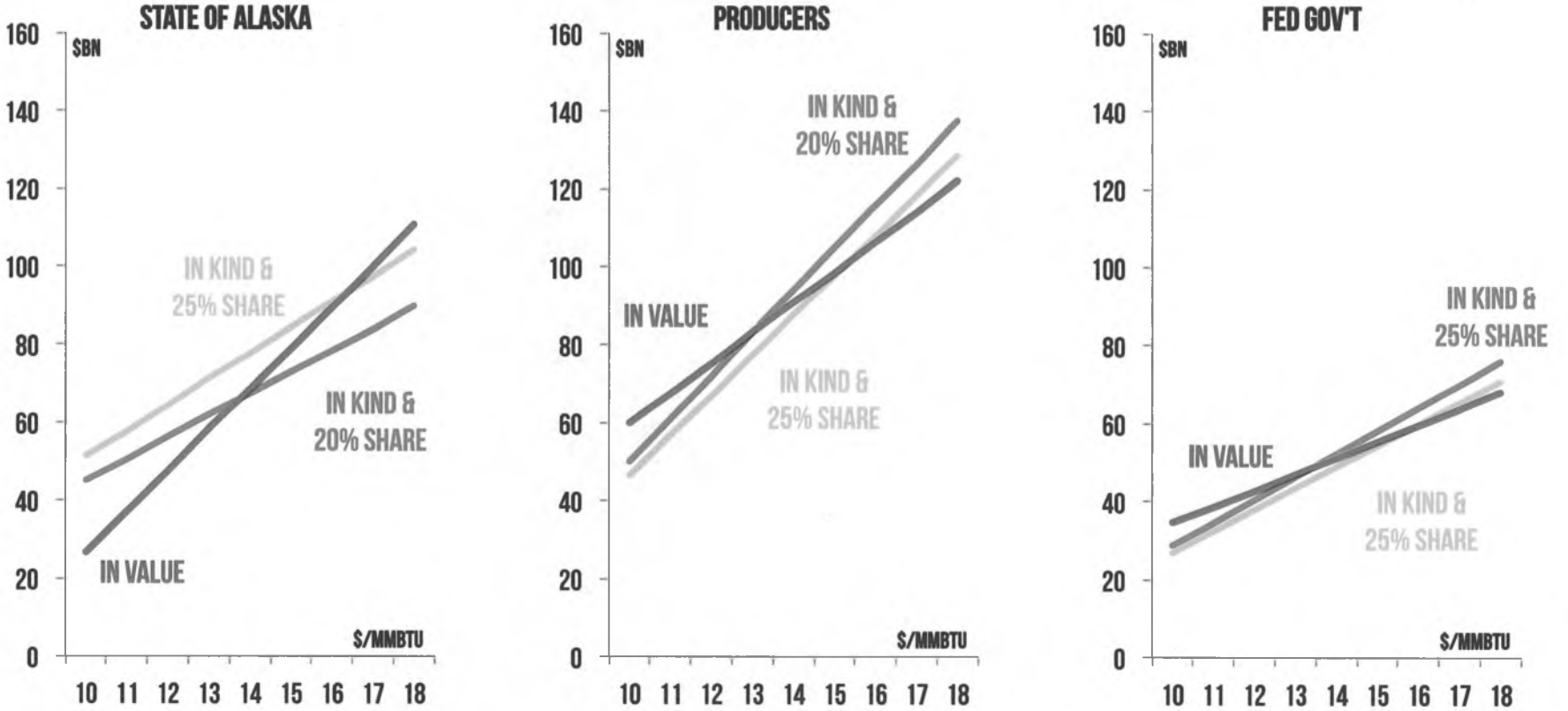


'IN KIND' W/ EQUITY OFFERS MORE DOWNSIDE PROTECTION

'In value' structure protects producers, not state, in low price environment because of tariff component

Higher SOA equity pushes up the price at which 'in value' is better than equity

CUMULATIVE CASH FLOWS OVER PROJECT LIFE

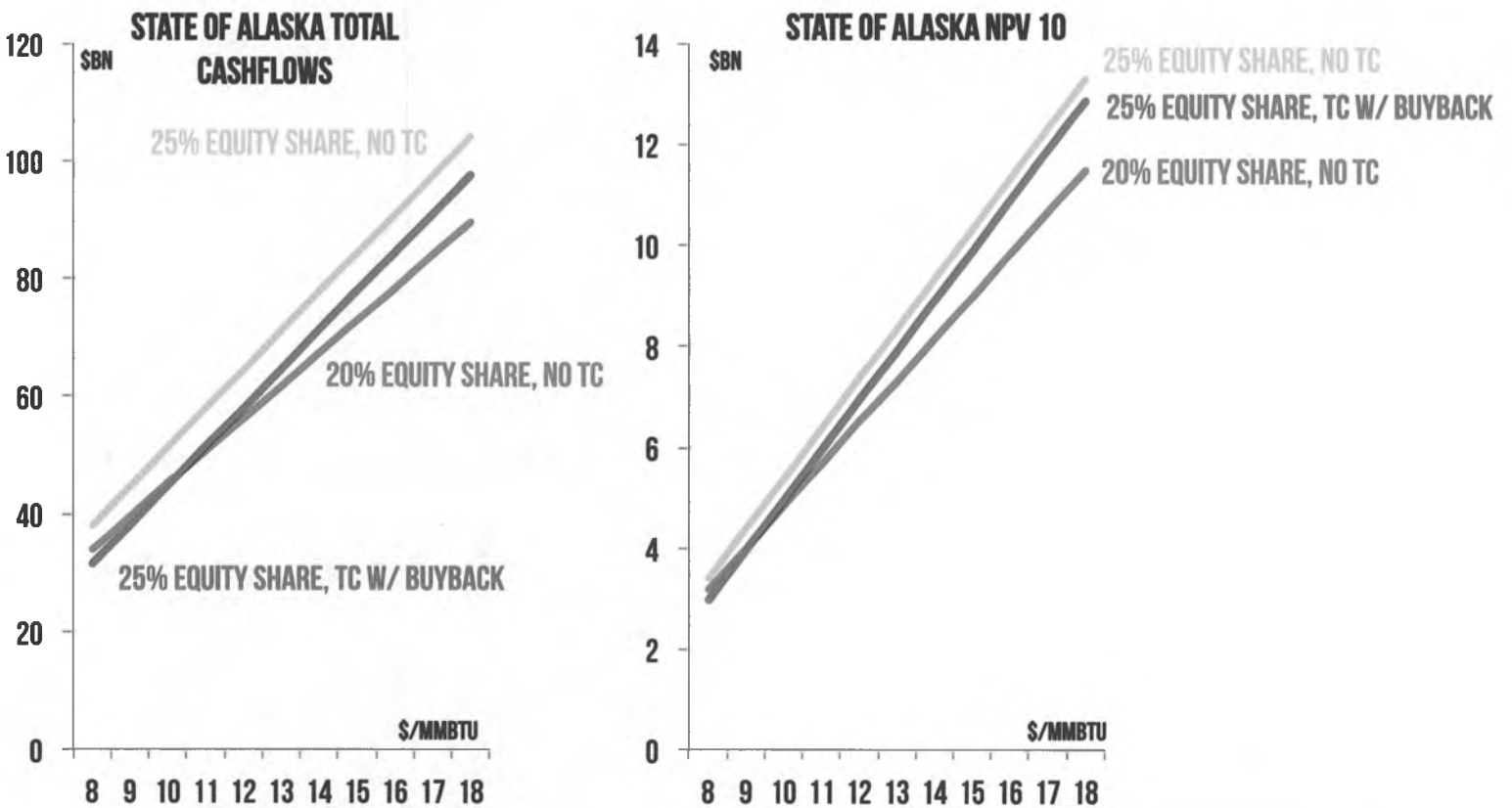


LIMITED VALUE FOREGONE UNDER TC W/ BUYBACK OPTION

Cash outlays under 25% equity share and TC w/ buyback option comparable to a 20% share without TC

Total cash flows and NPV10 are only moderately reduced compared to 25% share without TC

CUMULATIVE CASH FLOWS OVER PROJECT LIFE AND NPV TO STATE



OTHER QUESTIONS FOR THE MIDSTREAM

Should the state reimburse TransCanada's expenses under all scenarios; even if the project is no-go?

What does this imply for risk/reward split and appropriate locus of control?

How firm is 'off ramp' if state must offer TC participation if it continues with project within 5 years?

Should non-participants in an expansion benefit from lower costs if they share no risks of higher costs?

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ALASKA LNG: KEY ISSUES

MARCH 2014

Contents

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

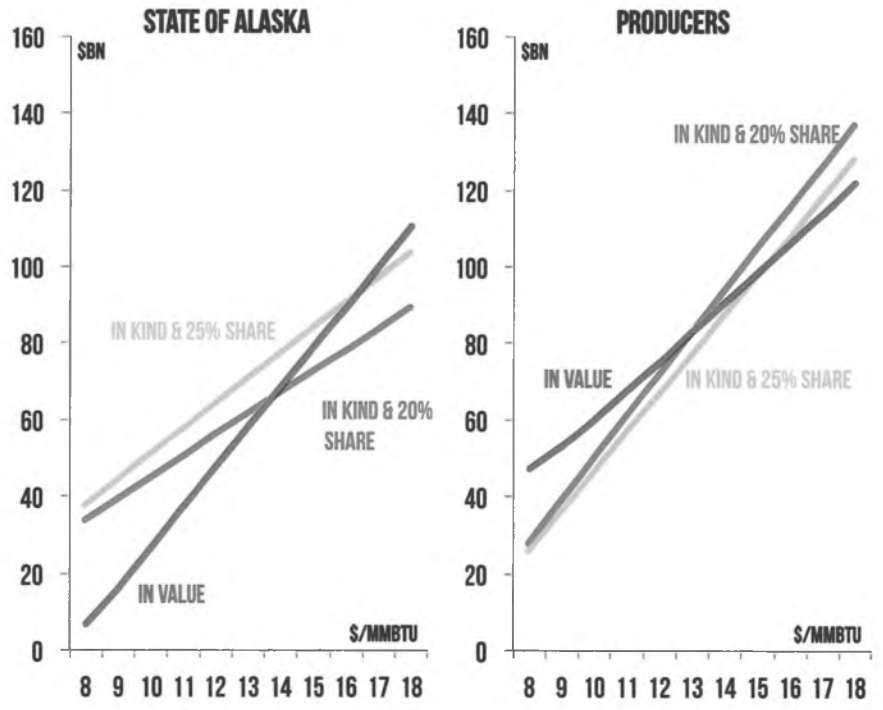
value', small movements in price or cost can wipe out value to the state altogether. The fixed midstream costs amplify the impact of price and cost movements on the state. Returns to the midstream are effectively 'guaranteed' in most circumstances, while the upstream, where the state draws its value, 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.

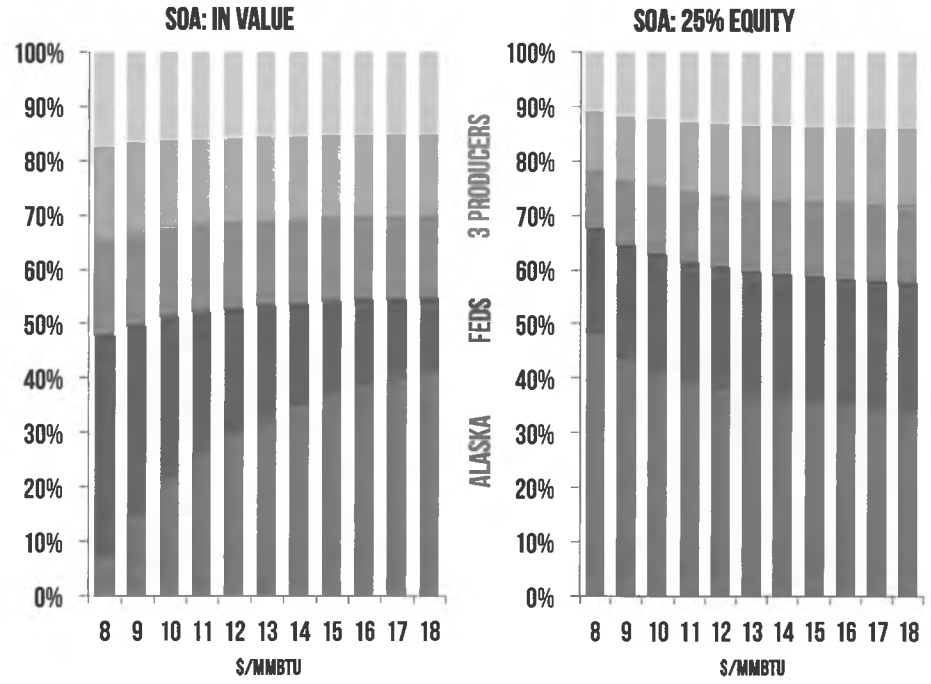
TOTAL UNDISCOUNTED PROJECT CASH-FLOWS TO STATE AND PRODUCERS AT DIFFERENT LNG PRICES



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).

SHARE OF UNDISCOUNTED PROJECT CASH-FLOWS AT DIFFERENT LNG PRICES



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.

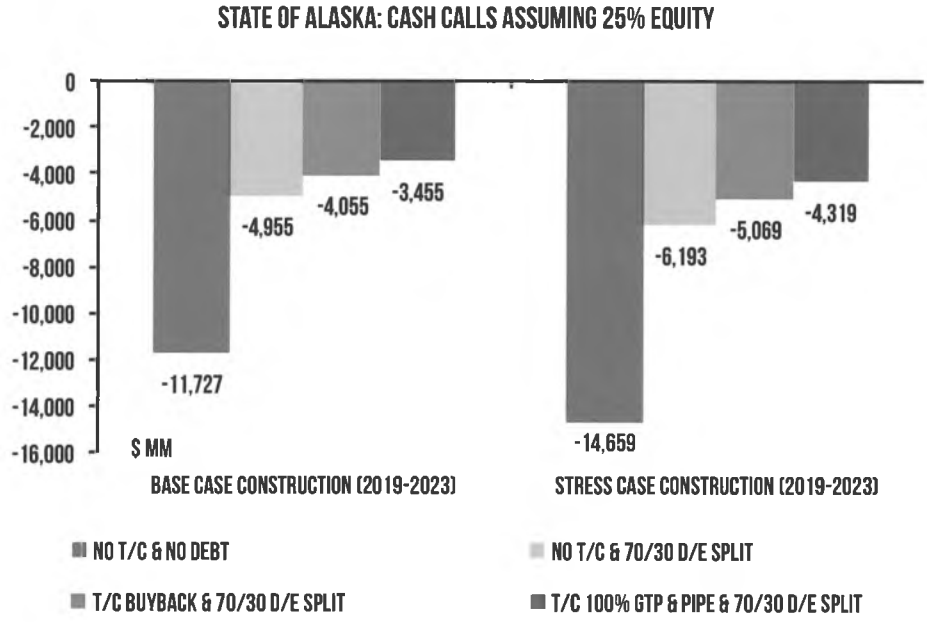
It is only if all the sponsors agree that the results of these studies are positive that a move to FID will be made. As such, **the state's loss in the case of a 'no-go' could be $600 million, at least based on today's understanding of what these studies are expected to cost.**

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).

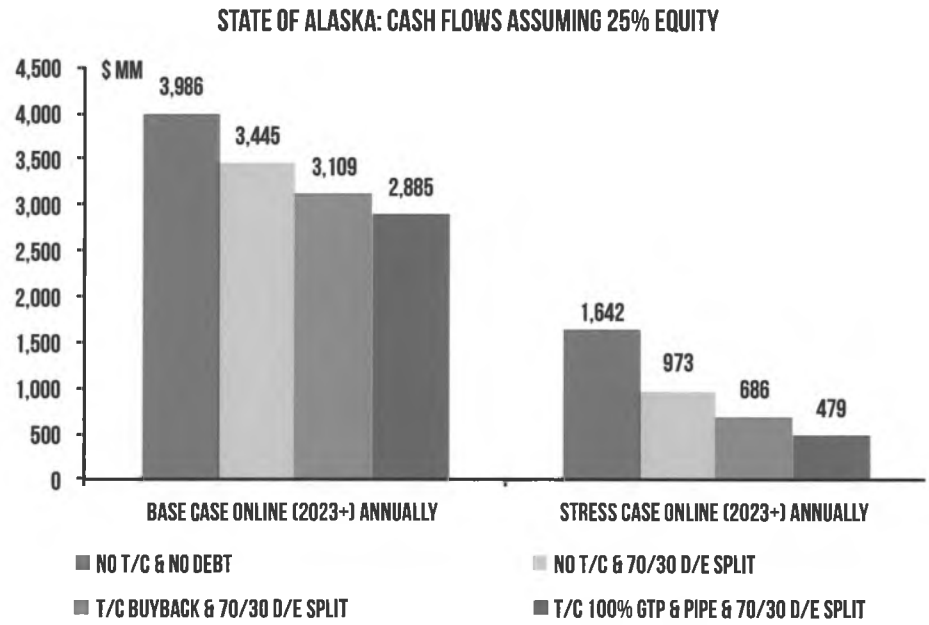
To quantify these risks, **we have developed a "stress case"** that estimates the financial implications of three combined risks:

- 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.**

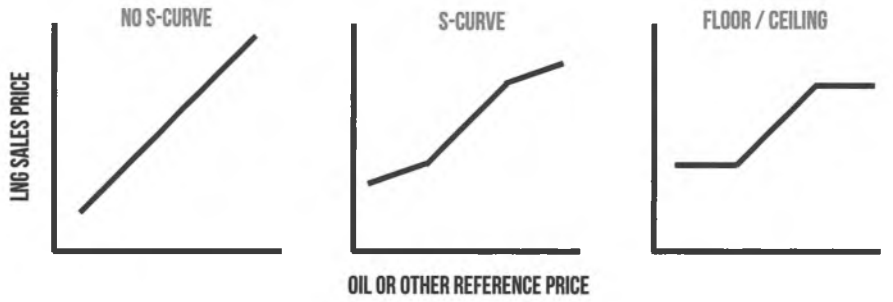
Just because the state might start out with 25% equity, it does not have to hold that equity—it can sell down as time goes by

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).

LEGAL SERVICES

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MEMORANDUM March 22, 2014

SUBJECT: Sectional Summary for CSSB 138(FIN) am
(Work Order No. 28-GS2806\I.A)

TO: Representative Eric Feige
Attn: Linda Hay

FROM: Donald M. Bullock
Legislative Counsel

You have requested a sectional summary of the above-described bill and a summary of the letter of intent adopted by the Senate.

As a preliminary matter, note that a sectional summary of a bill should not be considered an authoritative interpretation of the bill and the bill itself is the best statement of its contents. If you would like an interpretation of the bill as it may apply to a particular set of circumstances, please advise.

General

- Sections 1 - 12 and 57 relate to the Alaska Gasline Development Corporation (AGDC).
- Section 13 creates the Alaska affordable energy fund.
- Sections 14 and 15 address duties of the commissioner of natural resources.
- Sections 16 - 18 relate to oil and gas and gas only leasing.
- Sections 19 - 22 relate to the sale of royalty and include the sale of gas received in payment for the gas production tax.
- Sections 24 - 26 relate to expedited review and action by state agencies or entities.
- Sections 27 - 29 amend public disclosure statutes.
- Sections 30 and 31 amend the duties of the commissioner of revenue.
- Section 32 relates to confidentiality and records in the Department of Revenue that may be disclosed to the public.
- Section 33 amends a statute that apportions oil and gas income of a producer to the state for income tax purposes.
- Sections 34 - 54 relate to the oil and gas production tax.
- Section 55 amends a definition in the Alaska Gasline Inducement Act.
- Section 56 relates to the film production tax credit.
- Section 58 is uncodified law requesting the governor to establish an interim

advisory board.

- Section 59 is uncodified law relating to a plan for energy infrastructure needs.
- Section 60 is uncodified law relating to investment in the ownership of a North Slope natural gas pipeline.
- Section 61 is an uncodified transition section relating to regulations.
- Section 62 makes secs. 1 - 14, 16, 17, 23 - 27, 29, 30, 37, 39, and 55 - 61 take effect immediately.
- Section 63 makes sec. 38 take effect January 1, 2021.
- Section 64 makes sections not in secs. 62 or 63 take effect January 1, 2015.

Section by section summary

Bill sections relating to AS 31.25

*** Sec. 1.** Amends AS 31.25.005 by expanding the purpose of the Alaska Gasline Development Corporation (AGDC) to include an Alaska liquefied natural gas project (ALNGP). States that AGDC has primary responsibility for developing natural gas pipelines, the ALNGP, and other transportation mechanisms to deliver gas in the state. This section takes effect immediately under sec. 62 of the bill.

*** Sec. 2.** Amends the structure of AGDC in AS 31.25.010 to state that the corporation may dissolve when the corporation is no longer engaged in the development, financing, construction, or operation of an in-state natural gas pipeline or an ALNGP. This section takes effect immediately under sec. 62 of the bill.

*** Sec. 3.** Amends AS 31.25.040 (duties of the board) by adding two subsections. AS 31.25.040(c) requires the board to maximize efficient uses of state resources and to prevent the exchange of commercially sensitive information between the in-state natural gas pipeline project, the ALNGP, and other transportation mechanisms. AS 31.25.040(d) directs the board to hire a program director for the ALNGP that serves at the pleasure of the board and reports to the board and the executive director. This section takes effect immediately under sec. 62 of the bill.

*** Sec. 4.** Amends AS 31.25.080(a) (powers and duties of AGDC) by adding a reference to ALNGP in (a)(1), (a)(4), (a)(5), (a)(6), and (a)(21). Authorizes the corporation to acquire an ownership or participation interest in an ALNGP, natural gas treatment facilities, natural gas pipeline facilities, liquefaction facilities, and marine terminal facilities related to the infrastructure of an ALNGP or an ownership interest in an entity or joint venture that has an ownership interest in or is engaged in the development of an ALNGP. After consultation with the commissioner of revenue and the commissioner of natural resources, the corporation may enter into contracts relating to an ALNGP, including contracts for services related to operation, marketing, transportation, gas treatment, marine terminal operation, or liquefaction. This section takes effect immediately under sec. 62 of the bill.

* **Sec. 5.** Amends AS 31.25.080(e) by adding a reference to the in-state natural gas pipeline; the subsection requires notice to the legislature and the public if written commitments are received during an open season. This section takes effect immediately under sec. 62 of the bill.

* **Sec. 6.** Adds a new subsection to AS 31.25.080 (powers and duties of AGDC). The new subsection -- AS 31.25.080(g) -- prohibits an entity in or subsidiary of AGDC that is working on an in-state natural gas pipeline from also acquiring an ownership or participation interest in an ALNGP or in an entity or joint venture involved in the ALNGP. This section takes effect immediately under sec. 62 of the bill.

* **Sec. 7.** Adds a new subsection to AS 31.25.090 (confidentiality; interagency cooperation). The new subsection -- AS 31.25.090(i) -- allows AGDC to provide access to information that is related to the development of contracts under AS 38.05.020(b)(10) an d(11). Information provided to the commissioners is subject to the limitations on the disclosure of confidential information in AS 31.25.090(g). This section takes effect immediately under sec. 62 of the bill.

* **Sec. 8.** Amends AS 31.25.100 (in-state natural gas pipeline fund) to prohibit the use of money in that fund for a purpose other than the purpose of the corporation in AS 31.25.005(4), which is to develop in-state natural gas pipeline as described in the July 1, 2011 project plan prepared under former AS 38.34.040 (original project). This section takes effect immediately under sec. 62 of the bill.

* **Sec. 9.** Adds a new section -- AS 31.25.110 -- that establishes Alaska liquefied natural gas project fund. Establishes the fund in AGDC. Requires the AGDC to create an account in the fund for money appropriated for the ALNGP. Allows AGDC to use money in the fund without further appropriation for purposes related to the ALNGP and for managing the fund. This section takes effect immediately under sec. 62 of the bill.

* **Sec. 10.** Amends AS 31.25.120 (creation of subsidiaries) to authorize AGDC to transfer money from the in-state natural gas pipeline fund and the Alaska liquefied natural gas project fund to a subsidiary, subject to the limitations for the use of money in each fund. This section takes effect immediately under sec. 62 of the bill.

* **Sec. 11.** Amends AS 31.25.140(c) (exemption from the State Procurement Code; application of the Executive Budget Act; corporation finances) to require the board to also review the assets of the Alaska liquefied natural gas project fund (AS 31.25.110 in sec. 9 of the bill) as part of the board's annual review and report to the legislature. This section takes effect immediately under sec. 62 of the bill.

* **Sec. 12.** Adds a definition for "Alaska liquefied natural gas project," and describes components of the project: "gas pipeline," "gas treatment plant," "liquefied natural gas plant," "marine terminal," "Point Thomson unit gas transmission line," and "Prudhoe Bay

unit gas transmission line." This section takes effect immediately under sec. 62 of the bill.

* **Sec. 13.** Creates the Alaska affordable energy fund in AS 37.05.610. The fund is a special account in the general fund and consists of 10 percent of the revenue received from the state's royalty gas transported in the ALNGP. Money in the fund may be appropriated for the development of energy infrastructure in areas of the state that do not have direct access to a North Slope natural gas pipeline. The fund is not a dedicated fund. This section takes effect immediately under sec. 62 of the bill, but would not have money in the fund until royalty gas flows through the ALNGP.

Bill sections relating to the Alaska Land Act (AS 38.05)

* **Sec. 14.** Amends AS 38.05.020(b) to grant the commissioner of natural resources additional authority (1) to enter into commercial agreements for project services related to a North Slope natural gas project; (2) in consultation with the commissioner of revenue, negotiate agreements that include balancing, marketing, disposition of natural gas, and offtake agreements and contracts associated with the ALNGP; and (3) to enter into confidentiality agreements to protect information related to contract negotiations and contract implementation associated with a North Slope natural gas project. Agreements and contracts negotiated under AS 38.05.020(b)(11) to which the state is a party are not effective unless the legislature authorizes the governor to sign the agreements and contracts. This section takes effect immediately under sec. 62 of the bill.

* **Sec. 15.** Amends AS 38.05.020(b), as amended in the previous bill section, to authorize the commissioner of natural resources (in consultation with the commissioner of revenue) to take custody of gas received in kind as payment of the production tax on gas under AS 43.55.014(b) (a new provision in sec. 36 of the bill). Authorizes the commissioner of natural resources to manage the project services and disposition and sale of the gas received in kind for tax. This section takes effect January 1, 2015, under sec. 64 of the bill.

* **Sec. 16.** Amends AS 38.05.180(i) (in the oil and gas leasing provision) to refer to AS 43.55.011 rather than AS 43.55 as a reference to the oil and gas production tax. Limits the application of the exploration incentive credit to only taxes under AS 43.55.011 and not to the new tax applicable to gas for which an election is made to pay in kind under AS 43.55.014. This section takes effect January 1, 2015, under sec. 64 of the bill.

* **Sec. 17.** Amends AS 38.05.180 (oil and gas and gas only leasing) by adding new subsections -- (hh) and (ii) -- to authorize the commissioner of natural resources to propose modifications to a lease on the North Slope relating to switching between taking the state's royalty gas in value and in kind, to establish a method for establishing the fair market value for each component of the state's royalty gas, and establishing fixed royalty rates and modification of net profit shares. Requires the commissioner to make a written

determination supporting the modification that is based on a clear and convincing showing by the lessee of findings the commissioner must make in new subsection (ii). This section takes effect immediately under sec. 62 of the bill.

* **Sec. 18.** Amends AS 38.05.180(hh), as enacted by the previous bill section, to include the gas received by the state in payment of the gas production tax as a factor in determining whether a lessee or other person bears a disproportionate transportation cost with respect to the state's gas. This section takes effect January 1, 2015, under sec. 64 of the bill.

* **Sec. 19.** Amends AS 38.05.183(a) to require that gas received by the state as payment of the gas production tax be sold in the same manner as royalty gas. This section takes effect January 1, 2015, under sec. 64 of the bill.

* **Sec. 20.** Amends AS 38.05.183(c) to treat gas received by the state as payment of the gas production tax be sold in the same manner as royalty gas if the commissioner of natural resources determines that gas should be disposed without using competitive bidding. This section takes effect January 1, 2015, under sec. 64 of the bill.

* **Sec. 21.** Amends AS 38.05.183(d) to treat gas received by the state as payment of the gas production tax the same as royalty gas when considering the export of the gas from the state. This section takes effect January 1, 2015, under sec. 64 of the bill.

* **Sec. 22.** Amends AS 38.05.183(e) to treat gas received by the state as payment of the gas production tax the same as royalty gas when sold without using competitive bidding. This section takes effect January 1, 2015, under sec. 64 of the bill.

* **Sec. 23.** Amends AS 38.05.965 by adding definitions for "initial project term," "North Slope natural gas project," and "project services." This section takes effect immediately under sec. 62 of the bill.

Bill sections relating to an in-state natural gas pipeline (AS 38.34)

* **Sec. 24.** Amends AS 38.34.020(a) to require a state agency to expedite a review or take action that relates to a project under AS 31.25 (Alaska Gasline Development Corporation). This section takes effect immediately under sec. 62 of the bill.

* **Sec. 25.** Amends AS 38.34.020(b) to include a reference to a project under AS 31.25 (Alaska Gasline Development Corporation). This section takes effect immediately under sec. 62 of the bill.

* **Sec. 26.** Amends AS 38.34.020(c) to include a reference to a project under AS 31.25 (Alaska Gasline Development Corporation). This section takes effect immediately under sec. 62 of the bill.

Bill sections relating to public record disclosures

* **Sec. 27.** Amends AS 42.25.100(a) to state that confidential information relating to contract negotiations for a North Slope natural gas project under AS 38.05.020(b)(11) and (12), in sec. 14 of the bill, is not a matter of public record, with limited exception. This section takes effect immediately under sec. 62 of the bill.

* **Sec. 28.** Amends AS 42.25.100(a), as amended by the previous bill section, to incorporate the exception to protection from disclosure under new subsection AS 43.05.230(k) in sec. 32 of the bill. The new AS 43.05.230(k) allows the names of taxpayers and the volumes of production from leases paying gas production tax in kind under AS 43.55.014 in sec. 36 of the bill to be disclosed. This section takes effect January 1, 2015, under sec. 64 of the bill.

* **Sec. 29.** Amends AS 40.25.120(a) to protect information relating to contract negotiations for a North Slope natural gas project under AS 38.05.020(b)(11) and (12), in sec. 14 of the bill, from public disclosure as a public record. This section takes effect immediately under sec. 62 of the bill.

Sections relating to the administrative provisions for the Department of Revenue (AS 43.05)

* **Sec. 30.** Amends AS 43.05.010 (duties of the commissioner of revenue) to require the commissioner of revenue to consult with the commissioner of natural resources to negotiate contracts and development of terms in proposed contracts associated with a North Slope natural gas project. This section takes effect immediately under sec. 62 of the bill.

* **Sec. 31.** Amends AS 43.05.010, as amended by the previous bill section, to require the commissioner of revenue to enter into agreements with the commissioner of natural resources regarding the disposition of gas received as payment of the gas production tax in kind and to direct the disposition of revenues received from the gas. This section takes effect January 1, 2015, under sec. 64 of the bill.

* **Sec. 32.** Amends AS 43.05.230 by adding a new subsection -- (k) -- to treat as public information the name of each person electing to pay the gas production in kind under AS 43.55.014(a) (in sec. 36 of the bill) and the amount of gas produced from each lease or property subject to the election. This section takes effect January 1, 2015, under sec. 64 of the bill.

Relating to the corporation income tax (AS 43.20)

* **Sec. 33.** Amends AS 43.20.144(f) to state that gas subject to the election in AS 43.55.014, in sec. 36 of the bill, is included in the numerator and the denominator for purposes of the extraction factor. (The extraction factor is an element used to apportion

income of an oil and gas corporation income of a producer taxpayer to the state.) This section takes effect January 1, 2015, under sec. 64 of the bill.

Relating to the oil and gas production tax (AS 43.55)

* **Sec. 34.** Amends AS 43.55.011(e) to identify the period in which oil and gas is subject to the law in effect on January 1, 2014, and after December 31, 2021, when oil and gas is taxed separately. Excludes gas for which a tax is levied under AS 43.55.014, in sec. 36 of the bill. Provides that the taxable value of oil produced after December 31, 2021 is determined under AS 43.55.160(h), a new subsection added in sec. 50 of the bill. Provides that the tax on gas production is 13 percent of the gross value at the point of production after December 31, 2021. Provides that the gross value at the point of production for gas may not be negative for the purpose of determining the tax. This section takes effect January 1, 2015, under sec. 64 of the bill.

* **Sec. 35.** Amends AS 43.55.011(f) to provide for a minimum tax on oil produced north of 68 degrees North latitude after December 31, 2021. This section takes effect January 1, 2015, under sec. 64 of the bill.

* **Sec. 36.** Adds a new section to AS 43.55 -- AS 43.55.014 -- that provides for the production tax on gas produced from oil and gas leases that have been modified under AS 38.05.180(hh) in sec. 17 of the bill. Provides that the tax is 13 percent of the taxable gas produced and is to be paid in kind. Provides that the Department of Natural Resources shall manage the custody and disposal of the gas received as a payment in kind for the tax. Excludes certain gas from the tax under the section depending on the use of the gas or where it is flared, released, or allowed to escape. (The gas subject to this section must be produced from a lease that has been modified under AS 38.05.180(hh), so leases that are not state leases would not be included in this section. AS 43.55.014(b) refers to the gas produced from "each lease or property." Gas produced from state leases that have not been modified by AS 38.05.180(hh) and produced from land that is not subject to a state lease would pay the tax under AS 43.55.011(e)(3)(B) that is 13 percent of the gross value at the point of production.) This section takes effect January 1, 2015, under sec. 64 of the bill.

* **Sec. 37.** Amends AS 43.55.019(a) to limit the application of the education tax credit to the tax paid under AS 43.55.011(e) and not the tax paid in kind under AS 43.55.014 in sec. 36 of the bill. Allows for a contribution for vocational education equipment to be eligible for the education credit, and allows contributions under (a)(3) to be received by a nonprofit regional training center recognized by the Department of Labor and Workforce Development, and an apprenticeship program in the state that is registered with the United States Department of Labor under 29 U.S.C. 50 - 50b (National Apprenticeship Act). This section takes effect January 1, 2015, under sec. 64 of the bill.

* **Sec. 38.** Amends AS 43.55.019(a), as amended in the previous bill section, and as amended by session laws enacted in 2010, 2011, and 2012 so that the amendment to

AS 43.55.019 in sec. 37 will continue after 2020. This section takes effect January 1, 2021, under sec. 63 of the bill.

* **Sec. 39.** Amends AS 43.55.019(e) to conform to the amendment to AS 43.55.019(a), in the previous section of the bill, and to state that the education tax credit may not reduce a person's tax liability under AS 43.55.011(e) to below zero. This section takes effect January 1, 2015, under sec. 64 of the bill.

* **Sec. 40.** Amends the tax payment provisions in AS 43.55.020(a) to conform to the amendments to AS 43.55.011(e), in sec. 34 of the bill, and to AS 43.55.011(f), in sec. 35 of the bill. This section takes effect January 1, 2015, under sec. 64 of the bill.

* **Sec. 41.** Amends AS 43.55.020(g) to conform to the amendment to AS 43.55.020(a), in sec. 40 of the bill, that added an additional paragraph providing for an installment payment -- AS 43.55.020(a)(7) -- to the list of installment payments required to be paid and subject to interest when unpaid. This section takes effect January 1, 2015, under sec. 64 of the bill.

* **Sec. 42.** Amends AS 43.55.020(h) to conform to the amendment to AS 43.55.020(a), in sec. 40 of the bill, that added an additional paragraph providing for an installment payment -- AS 43.55.020(a)(7) -- to the list of installment payments required to be paid and subject to interest when overpaid. This section takes effect January 1, 2015, under sec. 64 of the bill.

* **Sec. 43.** Amends AS 43.55.020(*l*) to conform to the amendment to AS 43.55.011(e), in sec. 34 of the bill, to limit the application of the subsection relating to settlement with the royalty owner to oil and gas produced after December 31, 2013, and before January 1, 2022. This section takes effect January 1, 2015, under sec. 64 of the bill.

* **Sec. 44.** Amends AS 43.55.020 by adding a new subsection -- (m) -- that relates to the settlement with the royalty owner for oil and gas taxable under AS 43.55.011. Allows for the producer to deduct the amount of gas paid as tax under AS 43.55.014 or the value of the gas paid as tax under that section. This section takes effect January 1, 2015, under sec. 64 of the bill.

* **Sec. 45.** Amends AS 43.55.030(a) to require a producer to report the gross amount of gas produced and the amount of gas delivered to the state from each lease or property subject to an election made under AS 43.55.014. Requires a producer to report the production values of oil and gas under AS 43.55.160(a) and of oil under AS 43.55.160(h), as applicable; the new reporting is required because of amendments to AS 43.55.160. This section takes effect January 1, 2015, under sec. 64 of the bill.

* **Sec. 46.** Amends AS 43.55.160(a) to limit the application of the subsection to oil and gas produced before January 1, 2022. Amends the reference to AS 43.55.011(e) to

conform to the amendment to AS 43.55.011(e) in sec. 34 of the bill. This section takes effect January 1, 2015, under sec. 64 of the bill.

* **Sec. 47.** Amends AS 43.55.160(e) to refer to AS 43.55.160(h) as added by sec. 50 of the bill. This section takes effect January 1, 2015, under sec. 64 of the bill.

* **Sec. 48.** Amends AS 43.55.160(f) to conform to the addition of AS 43.55.160(h) in sec. 50 of the bill. Provides that the subsection does not apply to gas produced after December 31, 2021. This section takes effect January 1, 2015, under sec. 64 of the bill.

* **Sec. 49.** Amends AS 43.55.160(g) to conform to the addition of AS 43.55.160(h) in sec. 50 of the bill. Amends a reference to a lease or property to apply only to a lease or property "north of 68 degrees North latitude." Provides that the subsection does not apply to gas produced after December 31, 2021. This section takes effect January 1, 2015, under sec. 64 of the bill.

* **Sec. 50.** Adds a new subsection to AS 43.55.160 -- (h) -- for determining the production tax value of oil produced after December 31, 2021. Provides that the producer's lease expenditures incurred for exploration, development, or production of oil or gas deposits are deducted from the gross value at the point of production for the oil. (Note that gas produced after December 31, 2021, is taxed on the gross value at the point of production, but the lease expenditures associated with gas are deducted in determining the production tax value of oil for the lease or property.) This section takes effect January 1, 2015, under sec. 64 of the bill.

* **Sec. 51.** Amends AS 43.55.165(e) to provide that a tax levied under AS 43.55.014 is not a deductible lease expenditure. This section takes effect January 1, 2015, under sec. 64 of the bill.

* **Sec. 52.** Amends the definition of "gas processing plant" in AS 43.55.900(10) to clarify that a "gross processing plant" is upstream "of the inlet of any pipeline transporting gas to gas treatment plant." This section takes effect January 1, 2015, under sec. 64 of the bill.

* **Sec. 53.** Amends the definition of "point of production" in AS 43.55.900(20) by amending subparagraph (B). Amends subparagraph (B) to more specifically define that the point of production of gas is the point farthest upstream of the first point where the gas is accurately metered, the inlet of any pipeline transporting gas to a gas treatment plant, or the inlet of any gas pipeline system transporting gas to market. Deletes subparagraph (C), that relates to gas run through certain gas processing plants and gas treatment facilities that did not accurately meter gas after processing and before treatment. This section takes effect January 1, 2015, under sec. 64 of the bill.

*** Sec. 54.** Amends AS 43.55.900 by adding a definition for "gas treatment plant." Provides that a gas treatment plant may also perform gas processing and still be treated as a gas treatment plant. This section takes effect January 1, 2015, under sec. 64 of the bill.

Relating to the Alaska Gasline Inducement Act

*** Sec. 55.** Amends AS 43.55.900(18) so that the definition of "point of production" in AS 43.55.900 as it read on June 8, 2007 (the effective date of the Alaska Gasline Inducement Act (AS 43.90)). The amendment avoids changing the definition in AGIA after license applications were submitted, a license was awarded, and the first binding open season ended. This section takes effect immediately under sec. 62 of the bill.

Provision relating to the film production tax credit (AS 43.98.030)

*** Sec. 56.** Amends AS 43.98.030(c) to provide that the film production tax credit may only be used against the tax imposed under AS 43.55.011, and not against any other tax levied under AS 43.55. This section takes effect immediately under sec. 62 of the bill.

Repeal

*** Sec. 57.** Repeals AS 31.25.080(f) in the powers and duties of AGDC that related to the duty to coordinate and accommodate the developers of a large-diameter in-state natural gas pipeline. The repealed section is unnecessary after the amendments to AS 31.25 in secs. 1 - 12 of the bill. This section takes effect immediately under sec. 62 of the bill.

Uncodified law provisions

*** Sec. 58.** Adds a new section to uncodified law requesting the governor to establish an interim advisory board to advise the governor on municipal involvement in a North Slope natural gas project. This section takes effect immediately under sec. 62 of the bill.

*** Sec. 59.** Adds a new section to uncodified law requiring the Alaska Energy Authority to develop and deliver to the legislature a plan for developing infrastructure to deliver more affordable energy to areas of the state that are not expected to have direct access to a North Slope natural gas pipeline. This section takes effect immediately under sec. 62 of the bill.

*** Sec. 60.** Adds a new section to uncodified law that requires the commissioner of revenue to present a plan to the legislature that would allow a municipality, regional corporation, or a resident to participate as a co-owner of a North Slope natural gas pipeline. This section takes effect immediately under sec. 62 of the bill.

*** Sec. 61.** Adds a new section to uncodified law authorizing the Department of Revenue and the Department of Natural Resources to adopt regulations to implement the

Act. States that the regulations take effect under the Administrative Procedure Act, but may not take effect before the effective date of the provisions of the Act that are being implemented. This section takes effect immediately under sec. 62 of the bill.

Effective dates

* **Sec. 62.** Provides that the following sections take effect immediately: 1 - 14, 16, 17, 23 - 27, 29, 30, 37, 39, and 55 - 61.

* **Sec. 63.** Provides that sec. 38 takes effect January 1, 2021

* **Sec. 64.** Provides that the following sections take effect January 1, 2015: 15, 18 - 22, 28, 31 - 36, and 40 - 54.

Letter of intent

The letter of intent states the intent of the legislature that the parties involved in the Alaska Liquefied Natural Gas Project, "within the constraints of law" and some qualifications, will employ Alaska residents and contract with Alaska businesses, use job centers operated by the Department of Labor and Workforce Development, participate with the Department of Labor and Workforce Development to update the training plan for the ALNGP, advertise locally and use job service organizations to fill positions, provide training, and commit to negotiate labor agreements before the start of construction.

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THE STATE of ALASKA
GOVERNOR SEAN PARNELL

Department of Natural Resources
Joe Balash, Commissioner
Department of Revenue
Angela M. Rodell, Commissioner

March 21, 2014

The Honorable Eric Feige, Co-Chair
The Honorable Dan Saddler, Co-Chair
House Resources Committee
Alaska State Capitol, Room 124
Juneau, AK 99801

Dear Representatives Feige and Saddler:

Please find the following responses to questions, which were asked by committee members during the February 14, 2014 House Resources Committee meeting. Please see questions in italics and our responses immediately below the questions.

2/14/14 Questions from House Resources

Is the state's discussing commercial and fiscal terms with AK LNG a potential violation of the AGIA project assurances at AS 43.90.440? Is AK LNG a competing project? Are we already at risk for damages under AGIA?

No. The State's discussions with the AK LNG parties concerning fiscal terms are not a potential violation of AGIA because TransCanada is a participant in the process with the AK LNG parties – the State, the Producers and AGDC. Thus, the HOA, MOU and other discussions the State has with the AK LNG parties do not put the State at risk for damages under AGIA. The MOU signed by the State and TransCanada acknowledges that both parties need the enabling legislation currently before the legislature to authorize the State to negotiate commercial agreements with TransCanada and other project participants for the AK LNG project.

What would be the basis of determining the amount of a treble damages claim?

Assuming a claim by TransCanada for treble damages under AGIA could be sustained, it is not possible to know an exact amount, if any, which the State could be liable for, without knowing the specific facts and circumstances associated with a specific claim for treble damages. Under AGIA, AS 43.90.440, the maximum amount of the monetary basis for a treble damages claim by the licensee would be the amount of the unreimbursed qualified expenditures that were paid by the licensee net of reimbursements by the State, from the date the AGIA License became effective (December 5, 2008) to the date that the state first extended preferential royalty or tax treatment, or a

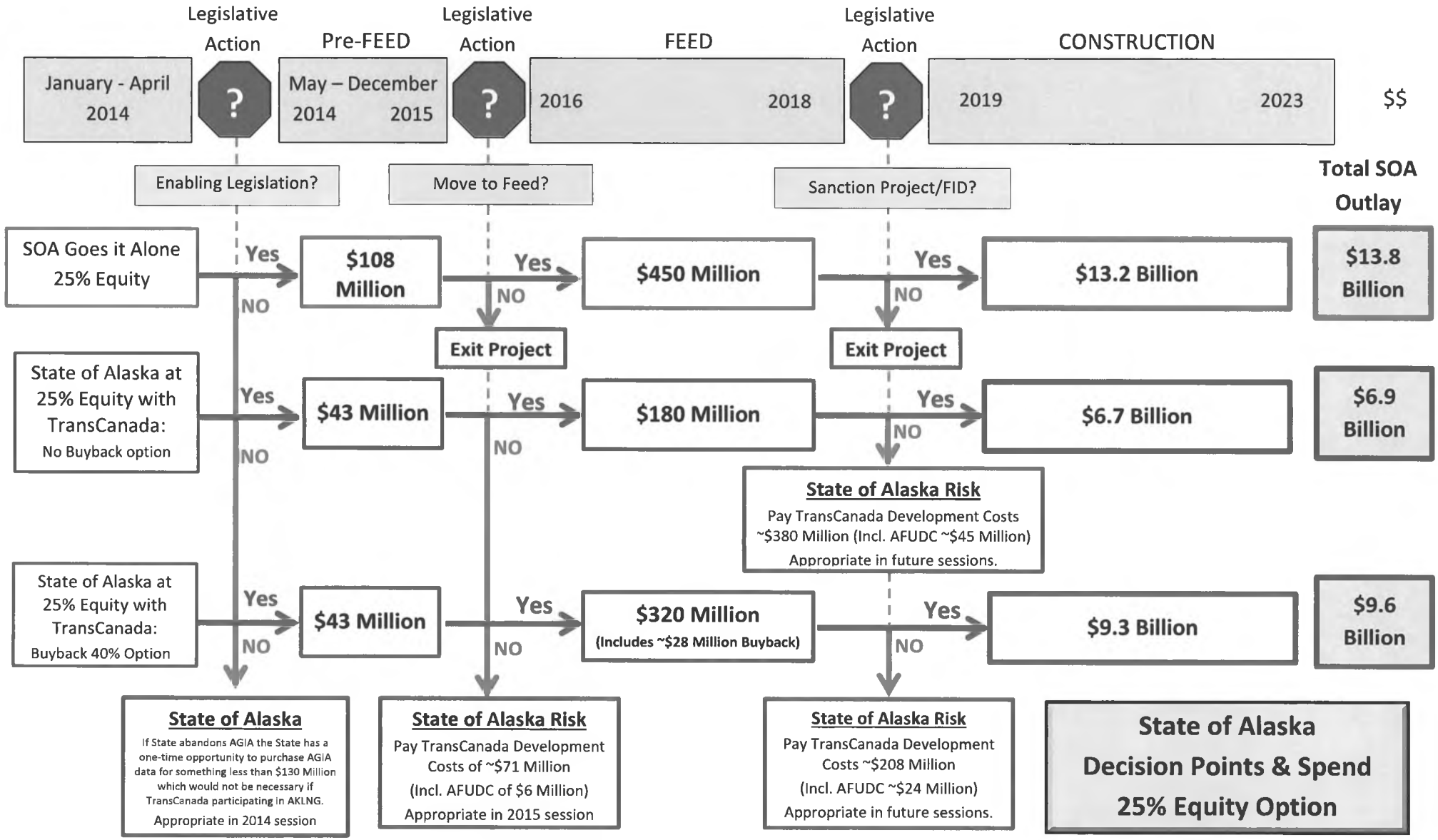
grant of state money, to another person for the purpose of facilitating the construction of a competing natural gas pipeline project - multiplied by three. The amount of treble damages is limited to the qualified expenditures incurred by the licensee that are not paid by the State. The State reimbursed TransCanada for 50 percent of qualified expenditures from the date the license was issued through the close of the first binding open season (July 30, 2010), and has reimbursed TransCanada for 90 percent of qualified expenditures since that date under AS 43.90.110.

We hope the House Resources Committee finds this information to be useful. Please do not hesitate to contact either of us if you have further questions.

Sincerely,

Joe Balash, Commissioner
Department of Natural Resources

Angela M. Rodell, Commissioner
Department of Revenue



ExxonMobil/ConocoPhillips/BP's combined share of the total project cost is approximately $41.2 Billion, which equals 75% of the total project costs.