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 Geran Tarr
Alaska State Representative
State Capitol, Room 114
Juneau, AK 99801

Dear Representative Tarr:

Please find the following in response to your questions asked via email on March 6, 2014. Please see the questions in italics and our responses immediately below the questions.

Answers to Questions 1-4, relating to **Governance Issues**, will be provided as soon as possible.

Expansion Issues

Can you provide an example of how the economics of tariff buildup, and the state's revenue, would work in event of an expansion? How would the relationships among the partners change including any modification to the state's ownership share?

A number of the specific details of the pro-expansion principles are still subject to negotiation in future agreements with the Producers, including exactly how the expansion costs would be treated. However, HOA Section A.1.3 provides that "if incremental capital costs of expansion on a unit of capacity basis are lower than the average pre-expansion capital costs per unit of capacity, the capital cost would be equalized, which could include some reallocation of past costs." For a compression expansion that reduces per unit capacity costs, please see the table appended to the end of this document, which illustrates how pre-expansion costs could be reallocated among the parties:

HOA Section A.1.3 also states that "both Expansion Parties and Non-Expansion Parties would share proportionately in any reduction in unit operating costs," while HOA Section A.1.2 states that fuel impacts of an expansion will be addressed by the parties in a future agreement during pre-FEED. The foregoing example does not address any impact of an expansion on unit operating costs or fuel costs.

If the state initiates an expansion without the producers / partners, and these partners have their tariffs lowered due to the capital averaging feature of the HOA, could their tariff be subsequently increased back to their initial levels by future expansions?

This question essentially asks whether, after low cost compression expansions have reduced all parties' per unit cost levels from the original cost levels borne by each party, the per unit costs for each party can be increased back up to the original per unit cost levels by "rolling in" the costs of a subsequent higher cost looping expansion. Section A.1.2 of Appendix A of the HOA provides, among other things, that Alaska LNG Parties that do not participate in a proposed expansion ("Non-Expansion Parties") will be kept whole and will not bear any expansion costs.

There are a number of details that are still subject to negotiation (such as the impact of an expansion on fuel costs, which will be addressed during Pre-FEED by the Parties). However, the language in HOA Section A.1.2 stating that Non-Expansion Parties "will not bear any costs related to the expansion" appears to preclude an increase in the capital costs borne by a Non-Expansion Party if a looping expansion were proposed that would result in higher per unit costs for Non-Expansion Parties if the looping costs were "rolled in" to the costs borne by each Party. [Note that while the question refers to tariffs, Appendix A refers to the costs borne by each Party, not tariffs, because some parties may elect not to have a stated tariff rate for their portion of the capacity of the project.]

If the state and TC are in disagreement over an expansion of the state's portion of the midstream, what is the process to resolve it?

MOU, Attachment C, Section 7 of the Midstream Services Term Sheet provides that TransCanada will expand the GTP and Pipelines when requested by creditworthy shippers on terms that are acceptable to TransCanada.

Section 7 further provides that if TransCanada fails to reach an agreement on expansion terms with the expansion shipper, then the State or a third-party designated by the State has the right to offer expansion terms to the shipper and undertake the expansion. Thus, if the state and TransCanada are in disagreement over an expansion of the state's portion of the pipeline/GTP components of the project, and cannot resolve the disagreement, the state itself can offer expansion terms to shippers.

The details of how Section 7 will be implemented will have to be negotiated between TransCanada and the State, and will be informed by the negotiations between the Producers and the State of the details of the pro-expansion principles set forth in Appendix A of the HOA.

Upstream Issues

We have heard that oil and gas production within Prudhoe Bay is approaching a tipping point in which it would be beneficial to pull gas out of the stream. Is there any modeling of how this may impact production from the IPA of Prudhoe Bay over time, due to both de-bottlenecking the reinjection facility as well as reducing the pressure in the field?

The administration's consultants have estimated the state revenue impacts for potential oil losses should they occur at Prudhoe Bay when gas begins to flow. Embedded in the model are assumptions about future oil and gas production, with the expectation that large-scale gas production will allow oil production to continue.

Given the oversight of the Alaska Oil and Gas Conservation Commission on this question, the producers will have to demonstrate – using a very sophisticated dynamic engineering model – that the oil will not be "wasted" as a consequence of large-scale gas production. We can also anticipate that the Prudhoe Bay producers will optimize oil production during the interim between now and first gas, given the requirements of the AOGCC for gas offtake and favorable economic factors governing future oil production (oil prices, capital and operating costs).

How is the definition of "Point of Production" different from what was envisioned in the Stranded Gas Development Act contract from 2006? Is it different for Prudhoe Bay vs. Pt. Thomson? How would the definition in the bill apply to a third field supplying gas to the project in the future?

The "Delivery Point" under the Stranded Gas Development Act (SGDA) is not inconsistent with the definition of "Point of Production" in SB 138. There is no similar "Point of Production" language in SB 138 for royalty because the law cannot impair the lease contracts and other agreements already in place.

The leases include language relating to the point of production and production costs. For example, the DL-1 Lease contract says that the "Lessee shall deliver free of charge (on said land or at such place as Lessor and Lessee mutually agree upon) … in good and merchantable condition…." The new form lease contract uses the phrase "from the leased or unit area" to refer to production subject to royalty together with the phrases "will be free and clear of all lease expenses…" and "delivered in good and merchantable quality…." Other agreements include the 1980 Royalty Settlement Agreement (the Field Cost Agreement that amended the DL-1 lease contract) that sets out allowable field costs at the "Intermediate Valuation Point" for royalty in-value gas and "the point of taking" for royalty in-kind gas. Under SB 138, Sections 17 and 18, the DNR commissioner will likely propose lease modification that will include a definition for a point of production that is consistent with the "Point of Production" definition for tax in Section 53 of SB 138.

Specifically, the "Point of Production" as defined in Section 53 of SB 138 "means (B) for gas that is (i) not subjected to or recovered by mechanical separation or run through a gas processing plant, the furthest upstream of the first point where the gas is accurately metered, the inlet of any pipeline transporting the gas to a gas treatment plant, or the inlet of any gas pipeline system transporting gas to a market; (ii) subjected to or recovered by mechanical separation but not run through a gas processing plant, the furthest upstream of the first point where the gas is accurately metered after completion of mechanical separation, the inlet of any pipeline transporting the gas to a gas treatment plant, or the inlet of any gas pipeline system transporting gas to a market; (iii) run through a gas processing plant, the furthest upstream of the first point where the gas is accurately metered downstream of the plant, the inlet of any pipeline transporting the gas to a gas treatment plant, or the inlet of any gas pipeline system transporting gas to a market." The Point of Production definition for the oil and gas production tax applies to all gas produced in the state.

Contrast this definition to the SGDA definition of the "Delivery Point" as "a location where Gas is metered for custody transfer either into the first Midstream Element or into a pipeline for shipment off a Property." It was to apply to both gas taken in-kind for tax and royalty. The SGDA definition of "Gas" is "a mixture hydrocarbons and *Impurities* in the gaseous phase." "Impurity" means "a non hydrocarbon substance contained in or removed from *Gas* including carbon dioxide, hydrogen sulfide,…" The "Midstream Element" means "a *Gas Transmission Pipeline*, a *GTP*, the *Mainline* or a *NGL Plant* if located in *Alaska*." [Emphasis in original.]

How is field gas (gas burned as fuel, flared, etc.) treated in the calculation of oil PTV in Section 42 (AS 43.55.160(h) [question referred to section 43, but calculation of oil PTV after 2022 is in bill section 42] of the bill? Is it any different than how it is taxed under current law? How is gas currently priced when it is used for this purpose?

Gas burned as fuel and flared is not counted as production for either tax or royalty purposes. For the production tax, AS 43.55.020(e) says "Gas flared, released, or allowed to escape in excess of the amount authorized by the Alaska Oil and Gas Conservation Commission is considered, for the purpose of AS 43.55.011 – 43.55.180, as gas produced from a lease or property. Oil or gas used in the operation of a lease or property in the state in drilling for or producing oil or gas, or for repressuring, except to the extent determined by the Alaska Oil and Gas Conservation Commission to be waste, is not considered, for the purpose of AS 43.55.011 – 43.55.180, as oil or gas produced from a lease or property." As long as the amount of gas flared or used for fuel is within AOGCC's acceptable limits, the gas is not counted as production and is not part of the calculation of the production tax value (whether for oil and gas combined as under current law, or for oil under SB 138).

This is further explained in DOR's tax regulations: 15 AAC 55.151(e) says "For purposes of AS 43.55 and this chapter, production of oil or gas does not include (1) oil or gas used in production operations on a lease or property in the state by the producer; (2) gas flared, released, or allowed to escape in amounts authorized by the Alaska Oil and Gas Conservation Commission; (3) oil or gas injected by the producer into a reservoir on a lease or property in the state in the course of operations for purposes of repressuring, including enhanced recovery, but not including storage …."

Royalty gas has similar provisions in the lease contracts. The DL-1 lease provides that royalties apply "Except for oil and gas used on said land for development and production." The new form lease says almost the same thing: "Except for oil, gas, and associated substances used on the leased area for development and production or unavoidably lost…" Gas used for fuel or legally flared on the lease is not considered a royalty bearing event.

Is the use of the term "in a gaseous state" in the definition of "North Slope natural gas project" (sec. 20 of the bill; AS 38.05.965(26)) intended to specifically exclude gas shipped as LNG for the Fairbanks trucking project? Why?

Section 23 of SB 138 defines "North Slope natural gas project" for purposes of eligibility for DNR lease modifications to mean a project to produce natural gas from state oil and gas leases for transport in a "gaseous state" from the North Slope. The administration's intent is that the Fairbanks

LNG trucking project would not be eligible for lease modification (e.g., relating to switching between taking the state's royalty gas in value and in-kind). The purpose of SB 138 is to allow the state to participate as an equity owner and shipper in natural gas pipeline projects for in-state use and export, like the Alaska LNG project. It does not involve the Fairbanks LNG trucking project, which was the subject of separate legislation and does not require the provisions of SB 138 to proceed.

Midstream and Operational Issues

As currently envisioned, how much room will there be in the initial pipeline for additional capacity through compression before the owners would have to start looping the pipeline? Assuming this is less than the amount needed for an additional LNG train, how much gas would this enable to be made available for in-state utility or industrial use?

The design of the pipeline, including pipeline diameter, has not been decided yet. Section 4.4 (c) of the HOA states that the sizing of the project components will be decided during pre-FEED. Attachment 2 of the October 2012 letter attached to the HOA described a 42- to 48-inch diameter pipeline. The February 2013 letter attached to the HOA described a 42-inch diameter pipeline. Assuming a 42 inch diameter pipeline, the addition of compression could deliver additional gas roughly equivalent to the amount of gas that could be processed by adding one LNG train to the LNG facility.

An important priority for the State is to ensure that the project components be properly sized to ensure sufficient capacity and gas for in-state use. While the amount of gas needed for in-state use is not certain at this time, it is a relatively small amount and there should be plenty of gas pipeline capacity and gas to meet in-state needs.

In one of Black and Veatch slides (#40 of the Royalty Study presented to Senate Finance on 2/10), they show various risks of taking Royalty in Kind. By far the greatest risk is on the marketing side, where they said "State expected to suffer discounted prices due to market inexperience and lack of diversity of supply." They said this could reduce our value by up to 75%.

We are told that the state can greatly reduce this risk by negotiating with producers to market our share of the LNG. Are there similar marketing arrangements in the world where a producer sells a sovereign's share into foreign markets? What is a typical commission rate or service charge paid for this service?

Yes, there are similar marketing arrangements where a producer sells a sovereign's share of gas (or oil) into foreign markets. For example, in Nigeria, the national oil company NNPC has equity lifting (i.e., sales) rights for the LNG produced of approximately 10%. NNPC rides on the coattails of each of the producers (equity lifting parties) and includes its 10% volume in the cargoes lifted by the producers, including parties such as Shell. NNPC's revenue received on the sale of the LNG is netted of all costs incurred by the producers in marketing, loading, shipping and offloading of each LNG cargo. It is difficult to determine exactly what marketing costs are incurred on each cargo but

NNPC is in effect charged a marketing fee by Shell and the other offtakers for each cargo lifted. The level of these costs is likely far less than 1% of the value of the cargo.

Although there are certainly other types of marketing arrangements elsewhere in the world (including some, such as in Norway, in which the sovereign's share is sold by a national oil company), the general type of arrangement seen in the Nigeria example is not unusual in production sharing agreement jurisdictions in other areas of the world.

We have heard reference to multiple possible regulatory regimes with FERC and RCA in different roles and different chapters of the FERC statutes coming into play. Can you explain in layman's terms how the decision is likely to be made over what is the appropriate regulatory regime(s) for the Alaska LNG project? Can you give examples of how the different regimes would work in practice?

The most important federal statute that applies here is the Natural Gas Act (NGA) which the FERC has primary responsibility for administering.

In the usual case of an interstate natural gas pipeline running from state A to state B, the FERC, acting under Section 7 of the NGA, will award a certificate of public convenience and necessity authorizing the construction and operation of that system. However, assuming no LNG from the AKLNG Project will reach the Lower 48, Section 7 will not apply because the transportation of North Slope gas will involve only one state. Since it will not be an interstate gas pipeline, Section 7 will not apply.

Section 3 of the NGA gives FERC exclusive jurisdiction to authorize the liquefaction plant for the AKLNG project. Because FERC has exclusive authority to approve the liquefaction plant, FERC also will be the lead agency for preparation of the environmental impact statement that will examine the entire project's impact on the environment, including the impact not only of the liquefaction plant but also the pipeline and gas treatment plant components of the project.

FERC's authority to regulate the rates and services of the liquefaction plant is limited at this time. Under Section 3, until January 2015, FERC cannot impose on an LNG terminal the traditional public utility-type regulation that the NGA applies to interstate pipelines, such as rate-setting and open access requirements. As of January of 2015, that prohibition will no longer apply, but what FERC will do at that time is not clear. However, Section 3 is flexible which suggests that parties will be able to structure a regulatory framework that addresses the needs of the Project's participants.

While FERC's jurisdiction under Section 3 to regulate the liquefaction plant is clear, the question of which agency has jurisdiction over the rates and services of the pipeline and GTP components of the project is less clear. Arguments can be made that either the FERC or the RCA has jurisdiction over the rates and services of the pipeline/GTP. Under the HOA, the parties have agreed that during pre-FEED they will advance the project under Section 3 at FERC, hold discussions with FERC staff regarding the application and implementation of Section 3, and discuss whether to file a petition asking FERC to confirm the access and pro-expansion principles set forth in the HOA.

Black and Veatch said that this project is larger than the LNG project envisioned and modeled as part of the 2008 AGIA license approval. What are the comparable volumes, sizes, and costs of that project?

Different LNG project configurations were considered during the 2008 AGIA Findings determination as shown below.

Alternative LNG Projects Considered During AGIA Findings Determination

LNG Project Alternative	Capital Cost ($ 2008) [1]
2.7 Bcf/d	$27 Billion
2.7 Bcf/d Expanded to 4.5 Bcf/d	$39 Billion
4.5 Bcf/d	$43 Billion
2.0 Bcf/d Y -Line Expansion	$18 Billion

[1] Capital costs estimated by the State's Technical Team during AGIA proceedings

The size and volume of the baseline configuration was approximately 2.7 Bcf/d (~15mtpa), similar in size to the AKLNG project being contemplated. Cost estimates have risen significantly since 2008 driven by competitive pressures in the global LNG and resource extraction industries. A comparison of the capital cost estimates between the 2.7 Bcf/d project considered during AGIA proceedings and the AKLNG Project is shown below.

Comparison of Capital Costs for LNG Project Considered During AGIA and AKLNG Project

Supply Chain Element	2008 Estimate	2013 Updates	
		State's Estimate	Producers Estimate
GTP	$5 Billion	$10 Billion	$10 - $15 Billion
Pipeline	$8 Billion	$12 Billion	$10 - $15 Billion
LNG	$14 Billion	$23 Billion	$17 - $24 Billion
Total	**$27 Billion**	**$45 Billion**	**$37 - $54 Billion**

Taxation Issues

The one-time agreement to pay Tax as Gas appears to be a way to lock in a fixed production tax rate over the term of the contract. Does this provision prevent future taxes, outside the terms of the contract, from being added by the legislature? Has there been any legal analysis of whether a producer's "irrevocable election" to pay tax as gas, as envisioned in the bill, would be constitutional?

The state percentage of participation in the AK LNG Project as contemplated in the Heads of Agreement (HOA) will be determined by the state's gas share, comprised of the state's royalty gas in kind and tax as gas. SB 138, Sections 17 and 18 adding subsection (hh) to AS 38.05.180, and the HOA in Article 8.1 contemplate that the Commissioner of Natural Resources will modify oil and gas lease provisions that relate to the state's ability to exercise its option to take royalty gas in kind and royalty gas in value.

The state will be agreeing to limit its flexibility to switch between taking royalty gas in kind and royalty gas in value to provide the project stability needed by all parties for capacity commitments and gas sales. HOA Article 8.1.3. Similarly, the producers will be agreeing to pay tax as gas, instead of money, to provide that same project stability. HOA Article 8.2. In Section 36 of SB 138, adding AS 43.55.014 provides that the Department of Revenue may allow a producer to make an election, under regulations adopted by the department, to pay tax as gas. This provision was changed in the CS SB 138 (FIN) to remove the word "irrevocable.[1]" The election in SB 138 applies only to gas produced from oil and gas leases modified under AS 38.05.180(hh)(which includes a commitment of gas for an initial project term) from which the DNR commissioner has determined to take royalty gas in kind. This provision does not affect the legislature's future tax authority and is not unconstitutional.

Can you explain, in a scenario where all the state's gas royalty will be in-kind, how the royalty obligation to the Permanent Fund would be calculated? Will the state be able to separately report the amount of revenue due to return on equity, royalty, tax, etc?

SB 138 contains provisions whereby producers of natural gas have the option to pay the State's royalty and tax on that gas "in kind." An "in kind" payment of royalty or tax in the case of natural gas production means that the State would receive natural gas as opposed to money (termed "in value") for its share of royalty or tax. Your question relates to how the State would calculate the royalty obligation to the Permanent Fund on the royalty taken in kind.

Alaska statutes currently provide for royalty on oil production to be paid in kind. The State's royalty oil taken in kind is normally sold to Alaska refineries. A portion of the revenue from the sale of royalty oil -- generally around 25% – is deposited in the Permanent Fund. This royalty oil is valued based on the sales price minus the transport costs to get the royalty oil from the North Slope to where it is sold. The royalty gas under SB 138 would be valued in the same way and be deposited in the Permanent Fund.

We anticipate being able to separately report revenue received from royalty, tax, return on the State's equity in the project.

Can you explain in more detail how the inclusion of TAG (Tax as gas) gas in the calculation of the corporate income tax (Sec. 27 of bill) could impact the apportionment formula? Could this result in an increase in the corporate income tax collected from oil producers?

SB 138 Section 36 establishes for the oil and gas production tax an option to pay the production tax in gas for gas produced from leases that have been modified under AS 38.05.180 (hh) (SB 138

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[1] Irrevocable" modified the producer's election under subsection (a) to pay the tax as gas, not the amount of the tax levy described under subsection (b).

Sections 17 and 18). The apportionment formula for corporate income tax for taxpayers engaged in oil and gas production is based on the taxpayer's apportioned business income; consisting of the taxpayer's share of production (extraction), property, and sales/tariffs in Alaska. This change ensures that gas produced but paid to the State as gas would be included in the apportionment factor. Given that the AKLNG Project overall would be an increase in business activity in the State it will likely result in higher apportionment factors and higher corporate income tax collections than would otherwise be the case.

Can we see modeling of field development costs in Pt. Thomson and how the ability to subtract 100% of gas lease expenditures (capital and operating) from oil PTV will impact oil revenue?

Information concerning field development costs for Point Thomson is not public. However, it is anticipated that deducting Point Thomson field development costs from a taxpayer's Production Tax Value would lead to a decline in oil production tax in the year the deduction is taken, that reduction would be more than offset by the corresponding increase in gas production and enhanced liquids recovery from the gas production.

Investment Issues

The MOU Equity Option term sheet mentions that the state's equity share could be owned by a state investment fund such as the CBR. Would it be possible for an equity investment to be made by fund managers, as part of their portfolio, without an act of appropriation by the legislature?

Yes, it would be possible for an equity investment to be made without a legislative appropriation, assuming the entity (DOR, ARMB, or APFC) charged with managing the assets of the fund determined the investment satisfied the investment criteria that they are bound by (see AS 37.10.071 and AS 37.13.120). It is the intent of the MOU to only allow the State or one of its funds to own the equity interest. An external manager would not actually "own" the equity option, but they could manage the option as it has been exercised by the State using state funds they manage.

The HOA, Article 10.1 (c), mentions that in-state infrastructure will be provided by the state. How broad is this obligation? Is there a difference between what infrastructure in the midstream would be provided versus in the upstream fields? Do you have any estimates of the cost of the state's required improvements, and are these estimates part of the consultants' revenue models?

The HOA recognizes that in-state infrastructure will be needed to support construction and operations of a large-scale LNG project. In Article 10.1(c), the administration agrees to support appropriations and permitting for the construction of necessary in-state infrastructure, like roads and bridges, including drafting, introduction and support of legislation appropriating funds and authorizing such construction. The Department of Transportation and Public Facilities will determine the state construction projects necessary to support the LNG project. The Alaska Legislature will determine whether such infrastructure receives appropriations to fund construction by passing legislation. It is possible that such infrastructure could be located on the North Slope near upstream fields or anywhere along the LNG project route to Southcentral Alaska.

Although a specific source of funding for the in-state infrastructure described in Article 10.1(c) is not in SB 138, it will be subject to future legislation and negotiations with the LNG project developers in the development of impact payments to the State and communities as described in Article 9.3.1(b). The revenue models presented to the legislature by the administration relating to SB 138 have not included the costs of additions to state infrastructure in Article 10.1(c), as such costs have not yet been determined. The Pre-FEED and FEED engineering work for the LNG project will enable DOTPF to determine state construction projects necessary to support the LNG project.

Debt and Financing Issues

The project envisions that the initial partners would be paying the state entirely with RIK and TAG. However, it's possible that an expansion shipper would be paying traditional Royalty in Value and production tax as cash, while also paying tariffs to the state if it was a state-initiated expansion. Could you describe how the economics of this scenario would work in practice?

An expansion shipper could potentially be paying royalty in value as well as production tax as cash. The State's revenue sources in that scenario from an expansion shipper would be:

- Royalty in value
- Production tax as cash
- State corporate income tax and
- Property tax

Assuming that the State's share of the project is expanded, the entities holding the State's ownership share in the AKLNG project (such as AGDC or TransCanada) would also receive Tariff payments for the service provided by the LNG Plant (and GTP and Pipeline, depending on the quality of the gas and the equity position that the State eventually takes in these project components) to the expansion shipper for the liquefaction, treating, and transportation of the expansion shipper's gas.

These tariff payments would be considered like a payment to a third party and, in turn, be allowed as a deduction for the purpose of calculating netback value in the determination of the expansion shipper's royalty and production tax obligations.

Can you explain in greater detail if there is a formula or other method to determine how the financing interest terms offered the state are expected to change as the state's overall debt level increases? Is there some rough connection between the debt level (or debt service as a percentage of GF) and the state's credit rating?

Slide 12 of the February 26, 2014 presentation to House Resources presented an illustration of how interest rates the state receives may change with the overall level of debt the state takes on. This illustration assumes 5% of General Fund Unrestricted Revenue (GFUR) is already devoted to other debt service, so the state could devote an additional 3% of GFUR to project-related debt and likely still achieve the most favorable financing terms. As the level of debt taken on increases, the credit rating on that debt would be lower, leading to higher interest rates on that debt, as shown in the illustration.

When considering offering debt for a project like this, when the market looks at our debt service as a percentage of revenue, do they consider the revenue as it currently is, or the revenue including what we will have after the completion of the project?

Rating agencies and market participants look the state's fiscal position over the life of the debt, from when it is issued through the term of the bond payments. Primarily however, they are concerned with the state's debt capacity during the period of time that the state will be making payments on the debt. For our analysis presented on February 26, 2014, we assumed that state General Fund Unrestricted Revenue and debt service after project completion would be the basis for determining the credit rating for project-related debt.

Does the restriction in the HOA that the state retain an A- credit rating limit our options for financing the project? Does it eliminate some of the theoretical "scenarios" as described in Commissioner Rodell's presentation?

The credit rating requirement is located in the TransCanada MOU, not the HOA. The HOA does not limit the state's ability to obtain financing for the AKLNG project, nor does it dictate that the state must achieve a certain credit rating for any debt that is issues in conjunction with the project or otherwise.

That said, project-related debt could be issued with a different credit rating than state General Obligation debt, and the requirement in the MOU could also be met with other alternatives like lines of credit. So no, the rating requirement in the MOU does not eliminate any of the scenarios that were presented to the committee.

Would it be possible to see the debt capacity, interest rate, and debt / equity scenarios at various state investment levels (25% / 10% or 22% / 8% as well as the 20% / 6% used in Commissioner Rodell's presentation?)

The attached slides show expected state obligations with 20%, 22%, and 25% state ownership, under the three ownership structures (state go it alone, TransCanada without buyback, TransCanada with buyback). Additionally, the slides show the total investment required under each of these options, as well as the debt / equity requirement assuming three debt service scenarios (3%, 5%, and 6% of GFUR). At this time, we have not prepared analysis for debt service of greater than 6% of GFUR.

Table (referenced on Page 1) illustrating how pre-expansion costs could be reallocated among the parties

ROW:	COLUMN:	B	C	D	E	F	G	H	I	J	K	L	M	N	O
		1	2	3	4	5	6	7	8	9	10	11	12	13	14
5		Pre-Expansion Capital Cost Share	Pre-Expansion Capital Cost	Pre-Expansion Capacity	Pre-Expansion Capital Cost/Unit Capacity	Expansion Capital Cost Share	Expansion Capital Cost	Expansion Added Capacity	Expansion Capital Cost/Unit Capacity	Total Capacity After Expansion	Post-Expansion Capital Cost / Unit Capacity	Total Capital Cost After Expansion	Potential Capital Cost Reallocation*	Post-Expansion Capital Cost Share	Post-Expansion Capacity Share
6	Producer A	25%	25.0	6.25	4	0%	0	0	NA	6.25	3.67	22.9	-2.08	20.8%	20.8%
7	Producer B	25%	25.0	6.25	4	0%	0	0	NA	6.25	3.67	22.9	-2.08	20.8%	20.8%
8	Producer C	25%	25.0	6.25	4	0%	0	0	NA	6.25	3.67	22.9	-2.08	20.8%	20.8%
9	State/TC	25%	25.0	6.25	4	100%	10	5	2	11.25	3.67	41.3	6.25	37.5%	37.5%
10	Total	100%	100	25	4	100%	10	5	2	30	3.67	110.0	0.00	100.0%	100.0%

* Plus indicates Give, Minus Indicates Receive

Assumes that Capacity Share = Capital Share

Example does not address impact of changes to operating or fuel costs.

Sample Calculation, inputs are in green

	1	2	3	4	5	6	7	8	9	10	11	12	13	14
	Pre-Expansion Capital Cost Share	Pre-Expansion Capital Cost	Pre-Expansion Capacity	Pre-Expansion Capital Cost/Unit Capacity	Expansion Capital Cost Share	Expansion Capital Cost	Expansion Added Capacity	Expansion Capital Cost/Unit Capacity	Total Capacity After Expansion	Post-Expansion Capital Cost / Unit Capacity	Total Capital Cost After Expansion	Potential Capital Cost Reallocation	Post-Expansion Capital Cost Share	Post-Expansion Capacity Share
Producer A	=25%	'=$C$10*B6	=$D$10*B6	=C6/D6	0%	=$G$10*F6	=$H$10*F6	=G6/H6	=D6+H6	=K10	=J6*K6	=L6-(C6+G6)	=L6/$L$10	=J6/$J$10
Producer B	=25%	=$C$10*B7	=$D$10*B7	=C7/D7	0%	=$G$10*F7	=$H$10*F7	=G7/H7	=D7+H7	=K10	=J7*K7	=L7-(C7+G7)	=L7/$L$10	=J7/$J$10
Producer C	=25%	=$C$10*B8	=$D$10*B8	=C8/D8	0%	=$G$10*F8	=$H$10*F8	=G8/H8	=D8+H8	=K10	=J8*K8	=L8-(C8+G8)	=L8/$L$10	=J8/$J$10
State/TC	=25%	=$C$10*B9	=$D$10*B9	=C9/D9	100%	=$G$10*F9	=$H$10*F9	=G9/H9	=D9+H9	=K10	=J9*K9	=L9-(C9+G9)	=L9/$L$10	=J9/$J$10
Total	=SUM(D6:D9)	100	25	=C10/D10	=SUM(F6:F9)	10	5	=G10/H10	=D5+H5	=(C10+G10)/(D10+H10)	=J10*K10	=SUM(M6:M9)	=SUM(N6:N9)	=SUM(O6:O9)

We hope that you find 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

Attachments