

SB

138

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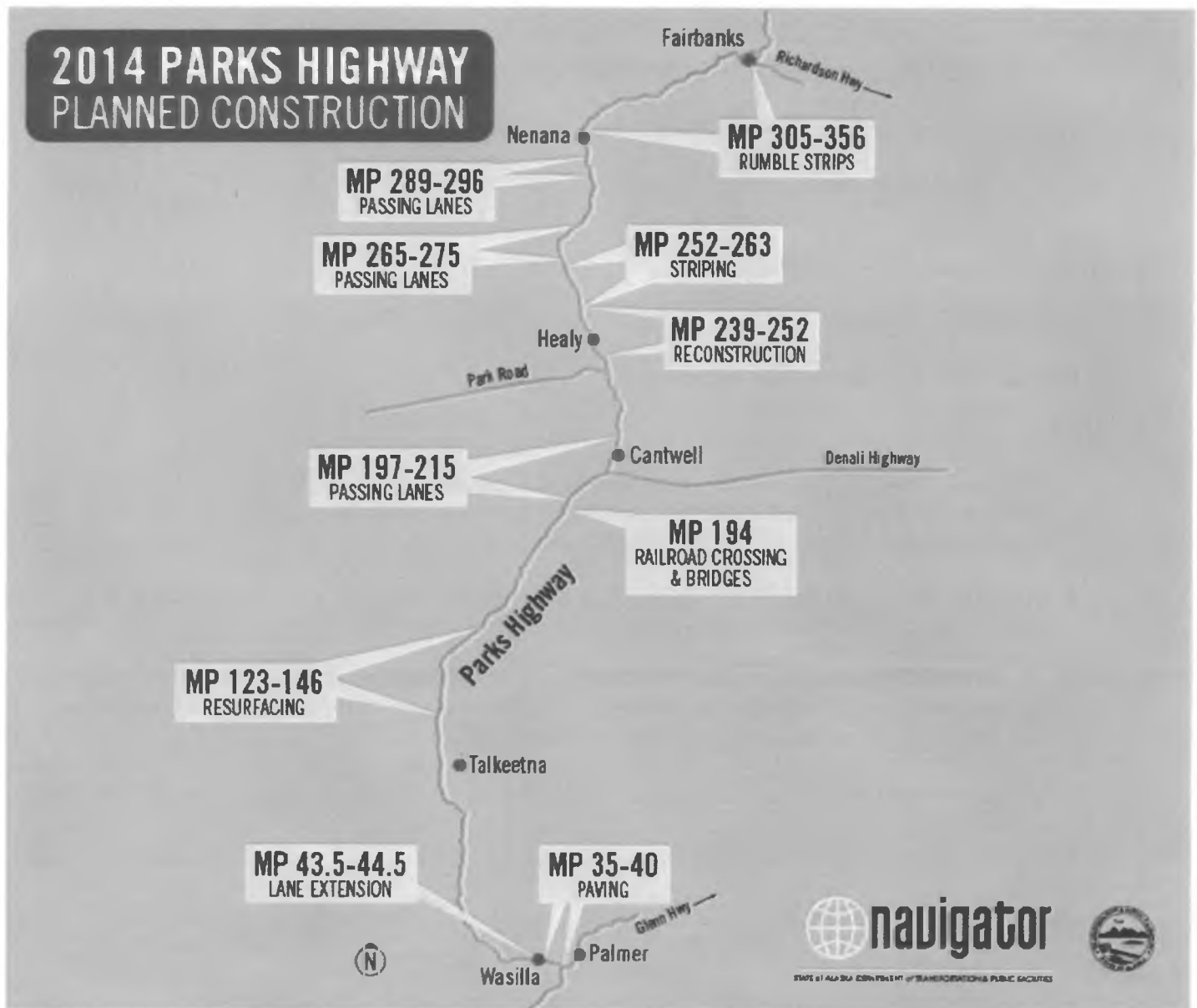
<TARGET><BILL>SB 138</BILL><SUBJECT>SB 138 (FILE
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Alaska Department of Transportation & Public Facilities/Parks Highway

Parks Highway Planned Construction Information - 2014

The Alaska Department of Transportation and Public Facilities will perform a significant amount of road construction on the Parks Highway during the 2014 construction season. Below is more information about each of the projects. For more details, including updated traffic control information such as delays, closures and weight restrictions, please visit www.AlaskaNavigator.org

Click yellow areas in the map below to find more information.



Parks Highway Construction Overview 2014

Parks Highway MP 239-252 Rehabilitation (Northern Region)

- **Scope:** Rehabilitate, resurface and construct passing lanes on approximately 13 miles between MP 239-252 near Healy. This will include bridgework, grading, paving, culverts and drainage and road widening.
- **Approximate schedule:** Anticipate construction to begin mid-April through October 2014 and conclude April-September 2015.
- **Impacts to traffic:**
 - Accumulated minimum delay of 45 minutes through the project. Reasons for delay will vary throughout the season depending on the work being performed, but at any time may include:
 - Delays of up to 20 minutes at various locations. During bridge work, expect delays and restrictions for overweight vehicles.
 - Five mile stretches of gravel surfaces with reduced speed limits of 45 MPH
 - Half-width lane closures for culvert replacements
 - Single-lane closures at no more than two bridges at a time throughout the project. There will be 72 hour break between closures to allow freight to move freely.
- **Construction cost:** \$32 million
- **Contractor:** Q.A.P., Inc.
- **Funding source:** Federal with state match
- **Why:**
 - **Safety:** This segment is widely regarded as the portion which needs rehabilitation the most. Two passing lanes added at MP 251 and MP 246 will provide drivers with means of passing slower moving vehicles safely to reduce crashes.
 - **Cost savings:** Several locations throughout the project area require frequent patching. This project will reduce maintenance costs by providing a new, more durable pavement structure.
 - **Drainage:** There are approximately 103 culverts throughout the project that will be replaced, repaired, cleaned or extended to prevent scouring, protect the road embankment and ensure the structure of the road remains stable.
- **Contact information:** Steve Oswald, Project Engineer, Steve.Oswald@alaska.gov. (218) 576-6645

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Parks Highway Passing Lanes, Stages 1 & 2 (Northern Region)

- **Scope:**
 - **Stage 1:** Construct three passing lanes. Work includes embankment upgrades, grading, paving, drainage, signing and striping at:

- **MP 272.6 - 274.7** (northbound and southbound lanes) – 23 miles north of Healy
- **MP 265.2 - 267.5** (southbound lanes) – 16 miles north of Healy
- **Stage 2:** Construct seven passing lanes. Work includes embankment upgrades, grading, paving, drainage, signing and striping at:
 - **MP 294.1 - 296.2** (northbound and southbound lanes) – 9 miles south of Nenana
 - **MP 289.5 - 291.6** (northbound and southbound lanes) – 16 miles south of Nenana
 - **MP 213.1 - 215.1** (northbound lane only) – 3 miles north of Cantwell
 - **MP 197.7 - 200.1** (northbound and southbound lanes) – 10 miles south of Cantwell
- **Approximate schedule:** Anticipate construction to begin mid-April through October in 2014 and April-September in 2015.
- **Impacts to traffic:**
 - Accumulated delay of 50 minutes through the project. Reasons for delay will vary throughout the season, but mostly as a result of major earthwork activities required for the construction of passing lanes. Condition of the construction zones at any time may include pilot cars, flaggers, unpaved surfaces and grade changes
- **Construction cost:** \$30 million
- **Contractor:** Great Northwest, Inc.
- **Funding source:** Federal with state match
- **Why:**
 - **Safety:** Adding passing lanes will provide drivers with means of passing slower moving vehicles safely in order to reduce crashes.
 - **Cost savings:** This project will reduce maintenance costs by providing a new and more durable pavement structure
 - **Drainage:** Replacing culverts prevent scouring, protect the road embankment and ensure the structure of the road remains stable.
- **Contact information:** Dave Arvey, Project Engineer, David.Arvey@alaska.gov, (907) 451-2621

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Parks Highway 252-263 Rehabilitation - season two remaining work (Northern Region)

- **Scope:** Work expected to take place during 2014 includes removing temporary striping, installing permanent striping & installing rumble strips.
- **Approximate schedule:** Construction will be complete by Aug. 31, 2014

- **Impacts to traffic:**
 - Accumulated delay of 20 minutes through the project for approximately 3-4 weeks. Reasons for delay will vary throughout the season depending on the work being performed, but at any time may include:
 - Pilot cars while temporary striping is removed and permanent striping is installed
 - Pilot cars while rumble strips are installed on both sides of the road
- **Construction cost:** \$13 million
- **Contractor:** Great Northwest, Inc.
- **Funding source:** Federal
- **Why:**
 - **Safety:** Adding rumble strips
 - **Cost savings:** This project will reduce maintenance costs by providing a new and more durable pavement structure.
 - **Drainage:** Replacing culverts prevent scouring, protect the road embankment and ensure the structure of the road remains stable.
- **Contact information:** Dave Arvey, Project Engineer, David.Arvey@alaska.gov, (907) 451-2621

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Parks Highway MP 194 Broad Pass (Northern Region)

- **Scope:** Reconstruct approximately one mile of highway and construct a railroad overpass and new bridge to cross the middle fork of Chulitna River
- **Approximate schedule:** Construction will be April-September in 2014; project will conclude September 2016.
- **Impacts to traffic in 2014:**
 - Accumulated delay of 20 minutes through the project. Reasons for delay will vary throughout the season depending on the work being performed, but at any time may include:
 - Flaggers and pilot cars for heavy, off-road equipment entering and exiting the highway or working on the shoulders
- **Construction cost:** Bid opening March 2014
- **Funding source:** Federal with state match
- **Why:**
 - **Safety:** Eliminate an "S" curve and remove an at-grade railroad crossing to improve safety in the pass for the traveling public.

- **Improve commerce:** Remove an at-grade railroad crossing by building a bridge over the railroad
- **Contact information:** Dave Hetman, Project Engineer, Dave.Hetman@alaska.gov, (907) 590-0219

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Parks Highway MP 305-356 Centerline Rumble Strips (Northern Region)

- **Scope:** Mill in centerline strips and install new centerline traffic paint between MP 305 and MP 356
- **Approximate schedule:** Construction will be 2-3 weeks total
- **Impacts to traffic:**
 - Short delays no longer than 20 minutes
 - Moving flagging operations
- **Construction cost:** \$593,000 (includes identical rumble strips on the Richardson Highway)
- **Contractor:** Specialized Pavement Markings, Inc.
- **Funding source:** Federal
- **Why:**
 - **Safety:** According to the most recently available crash data, there were 16 crashes in the project areas, including one fatality, where drivers crossed the centerline. These types of crashes can occur even during dry conditions. ADOT&PF will install rumble strips to mitigate these instances where drivers drift across the centerline into opposing traffic, as they are widely regarded as the top strategy to reduce these crashes
- **Contact information:** Jacob Mills, Project Engineer, Jacob.Mills@alaska.gov, (907) 451-2305

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Parks Highway MP 35-40 Pavement Preservation (Central Region)

- **Scope:** Resurface the Parks Highway from the Glenn Highway interchange to Seward Meridian Parkway including new striping, guardrail, end treatments and limited structural section repairs. Work also consists of repairing the expansion joint of the Seward Meridian Parkway bridge.
- **Approximate schedule:** Construction is expected for August 2014 and will be completed by Oct. 1, 2014.
- **Impacts to traffic:**
 - Night work mainly – 7 p.m. to 7 a.m.
 - May be temporary intermittent lane closures during day and night but will avoid peak traffic hours

- **Construction cost:** TBD
- **Contractor:** not yet selected
- **Funding source:** Federal with state match
- **Why:**
 - **Cost:** Extends the service life of from the Glenn/Parks interchange to the Seward Meridian Parkway.
 - **Safety:** Eliminating ruts, repairing the expansion joint of the Seward Meridian Parkway bridge, upgrading guardrail and installing new striping will provide a safer driving experience.
- **Contact information:** Kevin Jackson, Design Manager, kevin.jackson@alaska.gov, (907) 269-0641

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Parks Highway MP 123-146 Pavement Resurfacing (Central Region)

- **Scope:** Rehabilitate existing base with a foamed asphalt section which will be surfaced with up to 4" of asphalt concrete. Selected areas may require dig-outs. Drainage, clearing, signing, guardrail and other miscellaneous items of work will be done as necessary. Striping and rumble strips will be replaced.
- **Approximate schedule:** Tentatively scheduled for July through September 2014
- **Impacts to traffic:**
 - Accumulated possible delay of one hour through the project.
 - During bridge work, expect delays and restrictions for overweight vehicles.
 - Pilot cars and flaggers will direct traffic.
 - Five mile stretches of gravel surfaces with reduced speed limits of 45 MPH
 - Single-lane closures at no more than two locations at a time throughout the project. There will be 72 hour break between closures to allow freight to move freely.
- **Funding source:** Federal with state match
- **Why:**
 - **Extend the useful life of the roadway:** The general condition of the existing pavement is poor. Resurfacing this area will eliminate ruts and cracks, reducing maintenance costs.
 - **Support commerce by reducing weight restrictions:** This portion of the highway is subject to seasonal weight restrictions during the spring thaw, affecting the roadway's usability for hauling freight to the Interior and the North Slope.
- **Contact information:**

- Stephen Ryan, Design Manager, steve.ryan@alaska.gov, (907) 269-0537
- Laura Paul, Construction Project Manager, laura.paul@alaska.gov, (907) 269-0450

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Parks Highway MP 43.5-44.5 (Central Region)

- **Scope:** Improve capacity by extending the existing five-lane (four lanes with a two-way center left turn lane) from Lucas Road to Church Road, installing illumination, and improving the existing pedestrian pathway.
- **Approximate schedule:** Construction will be April - November 2014.
- **Impacts to traffic:**
 - Travel will be restricted from 8 p.m. to 5 a.m. with a maximum 20 minute delay during paving operations.
 - Pilot cars and flaggers will direct traffic.
 - Traffic restrictions to be mostly conducted at night with occasional restrictions during the day outside peak commuting hours.
- **Construction cost:** \$17 million
- **Contractor:** Quality Asphalt Paving, Inc.
- **Funding source:** Federal with state match
- **Why:**
 - **Safety:** Concerns have arisen at major intersections and for turning movements on and off the highway, as well as for non-motorized travel and off-road vehicles that use the corridor.
 - **Capacity improvement.** Traffic on the road has increased dramatically in recent years due to local development and increased through traffic.
 - **First portion of multi-phase project** (Lucas Road to Big Lake Road) estimated to be constructed between 2014 - 2018.
- **Contact information:** Laura Paul, Construction Project Manager, laura.paul@alaska.gov, (907) 269-0450

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Regional Public Information:

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Above Photo Banner: Work Zone on Parks Highway at MP 206. photo by Stacy Skrivanek, Alaska
DOT&PF

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Preliminary Agreements to be Negotiated Should Enabling Legislation Pass

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| Category | Agreement(s) | Signatory/Lead | Counterparty | Execution | Consultation | Legislative Approval |
|-------------------|--|-----------------------|------------------------------------|------------------|---------------------|-----------------------------------|
| General | AGIA Termination | DNR/DOR | TC | Q2 2014 | | No |
| Equity | Equity Option Agreement (EOA) | DNR | TC, AGDC | Q2 2014 | DOR | No |
| | Exercise Equity Option | AGDC | TC | Q4 2015 | DOR | Appropriation |
| | JVA (Pre-FEED) Joint Venture Agreement | AGDC | AKLNG Project Parties | Q2 2014 | DNR/DOR | Appropriation |
| | JVA (FEED) Joint Venture Agreement | AGDC | AKLNG Project Parties | Q1 2016 | DNR/DOR | Appropriation |
| Midstream | Precedent Agreement (PA) | DNR | TC | Q2 2014 | DOR | No |
| | Midstream Services Agreement (FTSA) | DNR | TC | Q4 2015 | DOR | Yes |
| | Liquefaction Services Agreement | DNR | AGDC | Q4 2015 | DOR | Yes |
| Upstream | Lease Modification | DNR | Producer Parties | Q4 2015/FID | DOR | No |
| | Balancing and Offtake | DNR | Producer Parties | Q4 2015 | DOR | Yes |
| Downstream | Preliminary Marketing/Disposition Agreements | DNR | Individual Producer Party or Other | Q4 2015/FID | DOR/AGDC | Yes |
| Other | Financing | DOR | TBD | TBD/FID | DNR | Yes - Public Vote? |
| | Impact Payment & PILT Proposal/Recommendations | DOR | AKLNG Project Parties | Q4 2014 | Communities | Yes - Statutory changes to enable |
| | Sales and Purchase Agreement (SPA) | DNR/Marketer | LNG Buyers | TBD/FID | DOR/AGDC | Yes |

Notes:

1. The list may not be inclusive of all the potential agreements necessary to advance the AKLNG Project.
2. "Agreement(s)" can include multiple agreements/contracts.
3. The "consultation" column reflects CS SB 138 fin am

Prepared by Department of Revenue/Department of Natural Resources. Revised 4/3/2014

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March 23, 2014

VIA E-Mail

Alaska State Legislature
Budget & Audit Committee
State Capitol, Room 514
Juneau, Alaska 99801

Re: The Alaska LNG Project

We have been asked to advise the State of Alaska ("State") on whether there are risks, and ways to minimize any such risks, under the federal antitrust laws in connection with the proposal for the State and four others to create a joint venture that would transport gas and produce LNG for consumption within Alaska and for export by ship to other markets.

In rendering this advice, we are primarily relying on information contained in (i) the Heads of Agreement dated January 14, 2014, among the State, the Alaska Gasline Development Corporation ("AGDC"), TransCanada Alaska Development Inc., ExxonMobil Alaska Production Inc., ConocoPhillips Alaska, Inc., and BP Exploration (Alaska) Inc. ("HOA"); (ii) the Memorandum of Understanding among the State, the TransCanada Alaska Company, LLC, Foothills Pipe Lines Ltd. and TransCanada Alaska Development Inc.; (iii) House Bill No. 277, introduced January 24, 2014; and (iv) the Senate Bill No. 138, also originally introduced January 24, 2014, but apparently subsequently modified.

Under the Heads of Agreement and HB 277, the Legislature is proposing to create a new a new AGDC subsidiary, AGDCS, to explore the feasibility of, and to develop, a large diameter gas pipeline from the North Slope and a LNG production plant in Southern Alaska.¹ Like its parent, AGDCS would be "a public corporation and government instrumentality for administrative purposes of the corporation, but having a legal existence separate from the state." [SB Section 7; HB Section 7] The Board of Directors would consist of the corporation's chairman, two state commissioners, and four public members selected by the Governor and

¹ We understand that a prior version of SB 138 also contemplated that AGDC would incorporate a new subsidiary. That feature is not contained in the current version of the Senate Bill. In any case, the existence of a separate subsidiary to AGDC does not affect the analysis contained herein.

serving at his pleasure. AGDCS would be one of the five corporate participants in the project; the other four are TransCanada Alaska Development Inc., ExxonMobile Alaska Production, Inc., ConocoPhillips Alaska, Inc., and BP Exploration (Alaska) Inc. (the latter three collectively “the Producers”) (*see* HOA).²

This project is generated by the need for the State and the Producers to respond to the changing market for natural gas in North America, largely as a result of the recent economical development of significant gas reserves from shale. This development has substantially increased the amount of gas already being supplied in the United States, and thereby made it uneconomic to build the previously planned Canadian natural gas pipeline from the North Slope to the Lower 48 US states. The Producers have large reserves of natural gas, and the State shares their strong interest in finding markets for it. This reality has led the State to join with the producers to develop the concept of (i) an 800 mile joint venture pipeline from the North Slope to southern Alaska and (ii) a large scale LNG plant and related facilities to convert the gas into a form that could be exported by ship, while also providing for distribution to Alaska residents in the more populous southern part of the State.

We believe that this large-scale, capital intensive project can be justified by applying the normal antitrust analysis contained in the Sherman and Clayton Acts; and any antitrust risks that remained could be eliminated by strengthening the legislative mandate to be sure that whole LNG project could be qualified for immunity under the so-called “state action” doctrine.

Antitrust Issues Related to the Creation of the LNG Joint Venture

There are generally two sets of antitrust questions that must be examined when a joint venture is being created: (1) Is the joint venture undertaking an activity that its members could not perform efficiently on an individual basis? (2) Is the size of the venture appropriate to its goals? In the case of the proposed Alaska LNG joint venture, the answers to these questions are clearly “yes”.

Where the joint venture is performing what the members have previously done on an individual basis, it may be treated as a de facto merger and hence struck down if it encompasses an unnecessarily high proportion of market participants. See, e.g., *United States v. Columbia*

² We note that, to the extent that AGDC/AGDCS would become an owner of a newly created entity or otherwise acquire interests in an entity to develop, own or operate an LNG plant, the acquisition of such interests could potentially implicate the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended. 15 U.S.C. § 7a. This statute is a notification statute which requires parties involved in certain acquisitions of voting securities or assets to notify the federal government before consummating such acquisition. At present, we do not seem to have sufficient information to advise the State on whether any such notification would be required, or if an exemption from such notification would be available.

Pictures Industries, Inc., 507 F. Supp. 412 (S.D.N.Y. 1980), *aff'd mem.* No 81-6003 (2d Cir. 1981). Alternatively, it may be treated as a thinly-veneered cartel, engaged in joint price fixing or market division. See *Timken Roller Bearing Co. v. United States*, 341 US 593 (1951); *United States v. Dynalectric Co.*, 859 F.2d 1559 (11th Cir. 1988). This problem does not appear with regard to the Alaska LNG joint venture. Pipelines and LNG production plants are subject to very large economies of scale. We are not aware of any evidence that any entity has plans to build a pipeline and LNG production plant on their own. And, given the regulatory approvals required for such a project, there appears to be no efficient way to meet the need to transport the gas except via a very large diameter pipeline that is being proposed. It would seem highly unlikely that the State (or the federal government) would approve for environmental and other reasons the building of multiple pipelines and LNG plants. Thus, single, larger scale facilities are perhaps the only practicable alternative to transport and market the North Slope gas.

The situation is quite different if a joint venture among some competitors is performing a necessary and efficient function, and the existing members exclude their rivals from access to the venture. Then the joint venture may be found to have engaged in a form of illegal boycott under Section 1 of the Sherman Act. See *United States v. Terminal RR Assn. of St. Louis*, 224 US 383 (1912); *Associated Press v. United States*, 326 US 1 (1945); *United States v. Realty Multi-List*, 629 F.2d 1351 (5th Cir. 1980). In these cases, the normal remedy is compulsory access for the non-member competitors. But this problem does not appear present with proposed Alaska LNG joint venture either. The Producers are major sources of natural gas from the North Slope and there is no evidence that there is any other gas producer who has been denied participation in the project. As long as the joint venture pipeline is willing to transport the gas of any smaller producers on reasonable terms, there is simply no antitrust issue with basic creation of the LNG joint venture. Such conditions appear to be reflected in the HOA where it specifically states that the State share of capacity would be owned and operated “on terms that would provide access for third-parties.” HOA, ¶ 6.3b.

1. Antitrust Issues Concerning Operational Rules of a Joint Venture

There has been a lot more antitrust litigation over how joint ventures actually operate than over their creation. A rule or decision of a joint venture will be treated as an “agreement” among its participating members and therefore subjected to more stringent antitrust scrutiny under Section 1 of the Sherman Act than a single firm monopolist would be for doing the same thing. See *American Needle v. NFL*, 130 S.Ct. 2201 (2010). However, it has become clear that, where the joint venture is performing a function that involves some plausible efficiencies, that its rules and decisions will be adjudicated under fact-intensive balancing process embodied in the so-called “rule of reason”, rather than a per se prohibition. See *NCAA v. Board of Regents*, 468 US 85 (1984). Thus the joint venture can set the prices and terms when it is offering a product

that is based on competitively produced inputs from its members. *See Broadcast Music, Inc. v. Columbia Broadcasting System, Inc.*, 441 US 1 (1979).

Reviewing the terms of the proposed joint venture among the State and the Producers, we do not see any rules that cause us immediate antitrust concern. The joint venture, as we understand it, will be the producer of the LNG gas for export and the seller of natural gas to the utilities serving consumers in Alaska. It will be free to set prices, quantities and terms for delivery without facing unusual antitrust risks. *Texaco Inc. v. Dagher*, 547 U.S. 1. In addition, the prices at which gas will be delivered to the venture will apparently be discussed/submitted to the Federal Energy Regulatory Commission for review and approval. *See* HOA, ¶ 6.4a. Such prices will therefore be considered regulated and will be essentially free from challenge under the so-called “filed rate doctrine” which prohibits antitrust damage actions in situations where rates were submitted/authorized by an agency with authority to determine whether the rate was appropriate. *Keogh v. Chicago & Northwestern Railway Co.*, 260 U.S. 156 (1922); *Wah Chang v. Duke Energy Trading and Mktg. LLC*, 507 F.3d 1222, 1226 (9th Cir. 2007).

We have reviewed Appendix A (entitled “Pro-Expansion Principles”) to the Heads of Agreement. We believe this has been done in a particularly effective way to avoid antitrust risks. A periodic problem occurs in a monopoly joint venture among competitors if one or more partners can veto expansion as a way to restrict supply and thereby generated supply shortages and higher prices in the downstream market. *See United States v. Pan American World Airways, Inc.*, 193 F. Supp. 18 (S.D.N.Y. 1961), *rev'd on other grounds*, 371 U.S. 296 (1963).

However, in Appendix A, it is made clear that any partner (including the State) may cause an expansion of the pipeline or the LNG plant so long as the Expansion Party will finance the addition and certain other conditions are met. The fact the State is a full partner makes this safeguard even stronger. Assume for some reason that the Producers wanted to hold down the pipeline capacity because they believed that resulting shortfall would result in higher prices for themselves. In these circumstances, the State could still exercise its right to be an Expansion Party, and thereby protect the consumer interests of its residents and voters.

2. Further Reducing Any Antitrust Risks by Enhancing the Legislative Mandate

As we have indicated, we do not see significant antitrust risks being generated by LNG joint venture’s creation or proposed operation. However, we have also had considerable experience where antitrust claims were made against a joint venture for tactical or anti-competitive reasons. The objector will formulate a “price fixing” or “boycott claim” which may be disruptive and expensive to defend. Because of the substantial expense of defending antitrust

litigation, the trouble-making plaintiff can impose serious costs on a joint venture and thus sometimes even cause it to abandon its preferred course.³

It is for the purpose of reducing any such risks that we make the following comments on how the proposed legislation *could be* modified to ensure that the LNG joint venture could gain the ability to make a strong "state action" exemption defense if sued by a troublemaking plaintiff or class of alleged victims assembled by some opportunistic lawyers.

First recognised in *Parker v. Brown*, 317 U.S. 341 (1943), the state action doctrine is a judicially-created exemption to the application of the federal antitrust laws where a state has imposed a restraint on competition. The state action doctrine immunizes anti-competitive conduct by private parties if a two-part test can be satisfied: (1) the challenged restraint must be one "clearly articulated and affirmatively expressed as state policy" and (2) policy must be "actively supervised" by the state itself. For entities that are considered the "state" for the doctrine's purpose, the second prong need not be established because the state presumably supervises itself.

Stated another way, in the absence of clear intent by the federal government to the contrary, the state action doctrine specifically allows a state to withdraw a sector of the economy from the competitive forces of the marketplace. As one court of appeals explained, "[w]hile individual anti-competitive acts of state governments may be considered unwise or counterproductive, the decision to make such choices lies within the sovereign power of the states. Congress did not intend to override important state interests in passing the Sherman Act." *A.D. Bedell Wholesale Co. v. Philip Morris Inc.*, 263 F.3d 239, 255 (3d Cir. 2001).

Here, the State of Alaska could make clear that, whatever its other goals and the antitrust risks of the Alaska LNG venture may be, it intends that its legislation and the subsequent operation of AGDC/AGDCS to displace the role of competition in the development and marketing of Alaska North Slope gas.⁴ For example, it could make somewhat clearer that the State's ultimate goal in passing HB No. 277 and SB No. 138 is to maximize the revenues from

³ See, e.g., Robert H. Bork, *THE ANTITRUST PARADOX* (1978) ("Litigation can be a particularly effective form of predation. Litigation can often be framed so the expenses to each party will be about the same....Expenses in complex business litigation can be enormous, not merely direct legal fees and costs but in diversion of executive time and effort and in the disruption of the organization's regular activities.") The incentives here may be modified somewhat by Alaska Rule of Civil Procedure 82 which incorporates a prevailing party attorneys' fee rule.

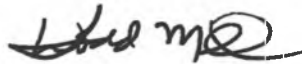
⁴ While we do not opine on existing Alaska law, we note that we did not come across a provision in existing legislation that makes clear that the State wants to displace market-based competition with its own market and/or regulatory structure with regard to the marketing of ANS gas.

the production of sale of ANS gas, consistent with the presumed goals of the producers. *But see Alaska Gasline Port Auth. v. ExxonMobil Corp.*, 2006-1 Trade Cas. (CCH) ¶ 75,312 (D. Alaska 2006) (Port Authority could not maintain action against gas producers for failing to supply gas to pipeline because, among other things, of apparent preemption of such actions by Stranded Gas Development Act, Alaska Stat. § 43.82.010, et seq.).

By making such goals clear in the legislation, Alaska would virtually eliminate (what we believe in any event is minimal) antitrust risk to AGDC and AGDCS in participating in such a venture. It has the virtue of allowing the state to determine if it also wants to extend such protection to the private parties participating in the Project because to do so, Alaska would need to establish some mechanism to “actively supervise” their activities within the Project to ensure that those activities are consistent with the State’s goals in authorizing the Project in the first instance. Such a role could be played by the Board of AGDC/AGDCS, which is comprised of, among others, state officials and public citizens appointed by the governor, or another agency or entity of the State of Alaska, if the State so desires it.

We trust that this letter is helpful in explaining the apparent federal antitrust law treatment of the proposed Alaska LNG Project and related legislation. We would be pleased to expand upon our analysis should the Legislature or the Committee so desire or to address any specific questions that the Legislature or the Committee may have.

Sincerely,



W. Todd Miller
Donald I. Baker



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ATTORNEYS AT LAW - A PROFESSIONAL CORPORATION

March 24, 2014 **Via E-mail**

Alaska State Legislature
Legislative Budget & Audit Committee
State Capitol, Room 514
Juneau, Alaska 99801

Re: Whether the Alaska Gasline Development Corporation's Interest in the Gas Project Contemplated by the Memorandum of Understanding, Heads of Agreement, and SB 138 and HB 277 Would Be Exempt from Federal Taxation

Our File No. 12463-01

Ladies and Gentlemen:

The Legislative Budget & Audit Committee of the Alaska State Legislature has requested advice about the tax implications and antitrust issues associated with the Governor of Alaska's gas pipeline and liquefied natural gas proposal. This letter addresses the tax exemption implications of the proposal, and revises and expands on the letter of March 23, 2014. The antitrust implications of the proposal are addressed in the March 23, 2014 letter of Baker & Miller PLLC.

We have been asked to review: the December 12, 2013 Memorandum of Understanding among the State of Alaska ("State"), Trans-Canada Alaska Company, LLC, Foothills Pipe Lines Ltd., Trans-Canada Alaska Development Inc. ("Trans-Canada"); the January 14, 2014 Heads of Agreement among the State, the Alaska Gasline Development Corporation ("AGDC"), Trans-Canada, ExxonMobil Alaska Production Inc., ConocoPhillips Alaska, Inc. and BP Exploration (Alaska) Inc., and the pending enabling legislation, originally submitted as Senate Bill 138 and House Bill 277.

The Memorandum of Understanding, the Heads of Agreement, and the current versions of Senate Bill 138 and House Bill 277 contemplate that the State would take an equity interest in part or all of an Alaska liquefied natural gas project, including design, development, construction and operation of the infrastructure and services required to

transport, liquefy, ship and market natural gas and associated hydrocarbons, specifically including a Prudhoe Bay unit gas transmission line, a Point Thomson unit gas transmission line, a gas pipeline, a gas treatment plant, a liquefied natural gas plant, and a marine terminal (the "Project"), and involving State ownership of, or participation in, up to 25% of the Project (the "Interest"). (As would be provided in AS 31.25.005(5) and AS 31.25.390(7) (Sec. 2 of CS for Senate Bill No. 138 (FIN) am)).

The purpose of the Project includes developing natural gas pipelines, to deliver natural gas in-state for the maximum benefit of the people of Alaska, to provide economic benefits and revenue to the State, and to maximize royalty and tax revenues from Alaska natural gas. (As would be provided in AS 31.25.005 (Sec. 1 of CS for Senate Bill No. 138 (FIN) am)).

The State's Interest in the Project would be held by AGDC,

a public corporation and government instrumentality acting in the best interest of the state for the purposes required by AS 31.25.005, located for administrative purposes in the Department of Commerce, Community, and Economic Development, but having a legal existence independent of and separate from the state.

(As would be modified in AS 31.25.010 (Sec. 2 of CS for Senate Bill No. 138(FIN) am)).

AGDC is governed by a board of directors consisting of five public members, appointed by, and serving at the pleasure of, the governor and subject to confirmation by the legislature and two individuals designated by the governor that are each the head of a principal department of the State. AS 31.25.020. The AGDC board shall appoint a program director and executive director for the Project. AS 31.25.040(d) and 31.25.045. The personnel of AGDC are exempt from AS 39.25, the State Personnel Act. AS 31.25.065.

AGDC has been granted the power of eminent domain, exercisable by filing a declaration of taking under AS 09.55.240 - 09.55.460, to acquire land or an interest in land that is necessary for the Project; the exercise of powers by AGDC may not exceed the permissible exercise of the powers by the State. AS 31.25.080(a)(4), as would be modified in Sec. 4 of CS for Senate Bill No. 138 (FIN) am.

The board of AGDC has been granted the power to "adopt regulations to carry out the purposes of [AS 31.25]". AS 31.25.130(c). AGDC is generally required to post proposed regulations for public comment at least 15 days prior to adoption. AS 31.25.130(d). Regulations adopted by AGDC's board shall be made available to members of the public and to the chair of the Administrative Regulation Review Committee under AS 24.20.400-24.20.460. AS 31.25.130(a).

AGDC has been given access by statute to the information of departments, agencies, and public corporations of the State that is directly related to the planning, financing, development, acquisition, maintenance, construction, or operation of the Project. All departments, agencies, and public corporations of the State are required to cooperate with, and provide information, services, and facilities to AGDC, and are generally required to give priority to processing authorization applications and other requests of AGDC. Further, the Department of Natural Resources is generally required to grant AGDC a right-of-way lease under AS 38.35 for the Project's gas pipeline transportation corridor at no appraisal or rental cost. AS 31.25.090.

The revisions proposed in SB 138 and HB 277 to AS 31.25.110 would authorize a Project fund, established in AGDC and consisting of money appropriated to it. AGDC would be responsible for fund management, but may contract with the Department of Revenue for fund management. If money were appropriated to the fund to finance the cost of the Project, AGDC would create an account in the fund for that purpose and hold the money appropriated for that purpose in that account. AGDC may use money appropriated to the fund without further appropriation for the purpose of managing the fund, for purposes related to the Project, and for purposes of transferring net revenue received to an appropriate fund as determined by the commissioner of revenue in consultation with the commissioner of natural resources.

AGDC has the power to form subsidiary corporations to develop, construct, operate, and finance in-state natural gas pipeline projects or other transportation mechanisms, although this power does not seem to cover owning an interest in a gas liquification plant and/or marine terminal, powers which seem to be reserved to AGDC itself. AS 31.25.120.

I. Whether AGDC Qualifies as a Political Subdivision of the State of Alaska.

If AGDC qualifies as a political subdivision of the State of Alaska for tax purposes, its income would not be subject to federal taxation, under the doctrine of implied statutory immunity.

Income earned by a state, a political subdivision of a state, . . . is generally not taxable in the absence of specific statutory authorization for taxing such income.

Rev. Rul. 87-2 (emphasis added).

The income of states and their political subdivisions is exempt from federal taxation because, with one exception,¹ the Internal Revenue Code does not expressly impose a tax on them. States and their political subdivisions are protected by implied statutory immunity, implied from the failure of the Internal Revenue Code to either expressly subject them to, or exempt them from, federal income taxation.² *E.g.*, Rev. Rul. 87-2; *Estate of Alexander J. Shamberg*, 3 T.C. 131, 146 (1944), *acq.*, 1945 C.B. 6, *aff'd*, 144 F.2d 998 (2d Cir. 1944), 1945 C.B. 335, *cert. denied*, 323 U.S. 792 (1944).

A political subdivision is a division of the state which has been delegated the right to exercise part of the powers of a sovereign. *Id.* To determine whether AGDC qualifies as a political subdivision of the State, and under implied statutory immunity is not subject to federal income taxation, the IRS applies the Treasury regulations interpreting § 103 of the Internal Revenue Code. Rev. Rul. 77-164; see also GCM 36,994 (Feb. 3, 1977). Under Treas. Reg. § 1.103-1(b), a “political subdivision” refers to “any division of any State or local governmental unit which is a municipal corporation or which has been delegated the right to exercise part of the sovereign power of the unit.” Sovereign powers include the power to tax, the power of eminent domain, and the police power. Rev. Rul. 77-164; *Estate of Shamberg*.

The first case to analyze the sovereign powers that a state or local subdivision must have to establish implied statutory immunity from federal taxation was the *Estate of Shamberg*, which concerned the Port of New York Authority (“Port Authority”). *Estate of Shamberg* is particularly important, as the structure of the Port Authority resembles in key respects the structure of AGDC. Specifically, the Port Authority was

endowed with the power of eminent domain, and with certain police powers, including the promulgation and enforcement of regulations for the conduct of navigation and commerce in the area defined as the Port of New York District.

Estate of Shamberg, 3 T.C. at 143.

AGDC likewise has the same two of the three sovereign powers, namely the power of eminent domain and certain police powers. First, AS 31.25.080(a)(4) provides that

¹ Namely, IRC § 511(a)(2)(B) imposes the unrelated business income tax on state colleges and universities.

² Implied statutory immunity is different from the constitutional doctrine of intergovernmental tax immunity, which formerly provided substantial protection to states and their political subdivisions from federal taxation. However, the Supreme Court of the United States has in recent decades held that states and their political subdivisions have no broad constitutional protection from federal taxation. *E.g.*, *New York v. United States*, 326 U.S. 572 (1946), and *Garcia v. San Antonio Metropolitan Transit Authority*, 469 U.S. 528 (1985).

AGDC has the power of eminent domain. Second, AGDC has significant police powers—AS 31.25.130(c) provides that the board of AGDC “may adopt regulations to carry out the purposes of [AS 31.25]”).

AGDC’s power under AS 31.25.130(c) to “adopt regulations to carry out the purposes of [AS 31.25]” is an example of a police power, one of the sovereign powers that can qualify AGDC as a political subdivision (and correspondingly exempt it from taxation). The police power

embraces regulations designed to promote the public convenience or the general prosperity, as well as regulations designed to promote the public health, the public morals or the public safety.

Philadelphia Nat’l Bank v. U.S., 666 F.2d 834, 840 (3d Cir. 1981), *cert. denied*, 457 U.S. 1105, 73 L. Ed. 2d 1314, 102 S. Ct. 2904 (1982) (quoting *Chicago, Burlington & Quincy Ry. Co. v. Illinois ex rel Drainage Comm’rs*, 200 U.S. 561, 592 (1906)).

Estate of Shamberg found that the Port Authority’s police powers included “the promulgation and enforcement of regulations for the conduct of navigation and commerce in the area defined as the Port of New York District.” As discussed above, AS 31.25.130(c) authorizes AGDC to “adopt regulations to carry out the purposes of [AS 31.25]” Further, AS 31.25 authorizes AGDC to build and own an interest in feeder and transmission natural gas pipelines, and a related LNG plant and marine terminal. In sum, the regulatory power under AS 31.25.130(c) is similar to the regulatory power held by the Port Authority at issue in *Estate of Shamberg* .

All three sovereign powers need not be delegated for AGDC to qualify as a political subdivision for purposes of § 103. Rev. Rul. 77-164, citing *Estate of Shamberg*, states that:

Three generally acknowledged sovereign powers of states are the power to tax, the power of eminent domain, and the police power It is not necessary that all three of these powers be delegated. However, possession of only an insubstantial amount of any or all sovereign powers is not sufficient."

(Emphasis added.)

IRS private letter rulings routinely grant political subdivision status to entities that have only one of the three sovereign powers, such as a library district with the power of taxation, a school district with the power of eminent domain, or a health care authority with the power of eminent domain. Ellen P. Aprill, *The Integral, the Essential, and the*

Instrumental: Federal Income Tax Treatment of Governmental Affiliates, *23 Iowa J. Corp. L. 803, 808-9 (1998)*.

If AGDC intends to qualify for federal tax exemption under implied statutory immunity, it is essential that AGDC retain substantial police (i.e., regulatory) powers under AS 31.25.130(c), in addition to the power of eminent domain. General Counsel Memorandum 37,771 noted that:

Whatever doubt exists as to exactly what constitutes the minimum amount of required "sovereign power" this Office is unprepared to concede that the possession of only one sovereign power is sufficient. We arrive at this conclusion after considering that the enumerated sovereign powers (taxation, eminent domain, police) can exist in an entity in only a minor degree and recognizing that all the facts and circumstances must be taken into consideration, including the public purposes of the entity and control of the entity by a government.

(Citing *Gen. Couns. Mem. 36,994*, at 7-8.)

Revenue Ruling 73-563 held that a rapid transit authority qualified as a political subdivision under Treas. Reg. 1.103-1 for purposes of issuing tax-exempt bonds because the authority, in part because it had the police power to set rates, determine routes, and enforce its regulations by maintaining a security force, but also because the state legislature empowered participating state governing bodies to levy retail and use taxes to fund the authority and authorized them to exercise the power of eminent domain on behalf of the authority. Likewise, SB 138 and HB 277, together with the statutes they modify, provide that certain State agencies are required by statute to assist AGDC by exercising certain police powers on behalf of AGDC, providing additional evidence that AGDC should qualify as a political subdivision.

Further, AS 31.25.090(a) provides AGDC with access to information of State departments, agencies, and public corporations directly related to the planning, financing, development, acquisition, maintenance, construction, or operation of the Project. All State departments, agencies, and public corporations are required by AS 31.25.090(a) to cooperate with, and provide information, services, and facilities to AGDC, and are generally required to give priority to processing authorization applications and other requests of AGDC. Finally, AS 31.25.090(d) generally requires the Department of Natural Resources to grant AGDC a right-of-way lease under AS 38.35 for the Project's gas pipeline transportation corridor at no appraisal or rental cost.

If AGDC intends to qualify for implied statutory immunity, it will need to address language in AS 31.25 that suggests that AGDC is not a political subdivision of the State. First, AS 31.25.240 states that obligations issued under AS 31.25 are not debts of "the

state or of a political subdivision of the state,"³ implying that AGDC is not a political subdivision. Second, AS 31.25.010 states that AGDC is an instrumentality of the State. As discussed below in the section on instrumentalities, an "instrumentality" for federal tax purposes is by definition something other than a state or a political subdivision of the state. In order to qualify for tax exemption under implied statutory immunity, AGDC will need to prove that it is, in fact, a political subdivision of the State regardless of the language in AS 31.25.010, and is not an instrumentality for federal tax purposes. Specifically, AS 31.25.010 provides that AGDC is

a public corporation and government instrumentality acting in the best interest of the state for the purposes required by AS 31.25.005, located for administrative purposes in the Department of Commerce, Community and Economic Development, but having a legal and existence independent of and separate from the state.

AS 31.25.010, as would be modified in Sec. 2 of CS for Senate Bill No. 138(FIN) am (emphasis added).

Treasury Regulation § 301.7701-1(a)(3) provides that an entity that is separate from a state or political subdivision "is not always recognized as a separate entity for federal tax purposes."⁴ For instance, the Second Circuit held in *Estate of Shamberg* that the Port Authority of New York qualified as a political subdivision, even though the Port Authority's authorizing statutes provided, similar to AS 31.25.010 describing AGDC as a "public corporation and instrumentality," that the Port Authority is

a body politic and corporate⁵ created by a compact made between the States of New York, [^{**5}] Laws N.Y. 1921, c. 154, and New Jersey on April 30, 1921, N.J.S.A. 32:1-1 et seq., and approved by Congress on August 23, 1921, 42 Stat. 174.

Estate of Shamberg at 1000 (emphasis added). See also Rev. Rul. 70-562 (finding that a county board of education, described as an instrumentality of the state, qualified as a political subdivision—an acceptable charitable donee under § 170(b)(1)(A)).

³ Note that AS 31.25.240 does not say that obligations issued under AS 31.25 are not debts of "the state or of another political subdivision of the state," etc.

⁴ Adding, by way of example, that "an organization wholly owned by a State is not recognized as a separate entity for federal tax purposes if it is an integral part of the State."

⁵ AGDC is similarly described as a "body corporate and public" in AS 31.25.260(b), dealing with the tax exempt status of its bonds.

In order to clarify that AGDC qualifies for federal tax exemption under implied statutory immunity, the State is advised to consider revising SB 138 and HB 277 to provide that AGDC is a political subdivision, at least for purposes of its eminent domain and police (i.e., regulatory) powers, as well as for tax exemption purposes, and also consider revising language in AS 31.25.240 and AS 31.25.010 suggesting that it is not a political subdivision.

Further, the State is strongly recommended to secure a private letter ruling confirming that AGDC qualifies for tax exemption under implied statutory immunity as a political subdivision of the State.

II. **Whether AGDC is an Integral Part of the State.**

If AGDC did not qualify for exemption from federal taxation as a political subdivision of the State, the question would then be whether AGDC qualifies for tax exemption as an integral part of the State or a political subdivision of the State.

Alaska Statutes 31.25.010 provides that AGDC is a:

public corporation and government instrumentality acting in the best interest of the state for the purposes required by AS 31.25.005, located for administrative purposes in the Department of Commerce, Community, and Economic Development, but having a legal existence independent of and separate from the state.

(Emphasis added.)

This corporate separation raises the issue whether AGDC would be treated as a taxable corporation under federal law, separate from the State of Alaska, which is not subject to federal taxation. A corporation is generally treated as separate from its shareholders for tax purposes. *Moline Props., Inc. v. Comm'r*, 319 U.S. 436, 438-439 (1943).

Whether AGDC qualifies as an integral part of the State turns on whether its corporate status would prevent AGDC from being treated as an integral part of the State for tax purposes.

Over the years, the IRS has extended the income tax exemption it provides to states and political subdivisions to entities it regards as their "integral parts." See Rev. Rul. 87-2, 1987-1 C.B. 18; see *also* Treas. Reg. § 301.7701-1(a)(3).

IRS Announcement 2011-78, n. 24, 2011-51 I.R.B. 874 (12/19/2011) (emphasis added).

Revenue Ruling 87-2 provides that:

Income earned by . . . an integral part of a state or political subdivision of a state is generally not taxable in the absence of specific statutory authorization for taxing such income.

(Emphasis added). In other words, even if AGDC failed to have any sovereign power qualifying it as a political subdivision of the State, AGDC could still be exempt from federal income tax if it is an integral part of the State or one of its political subdivisions.

Although AS 31.25.010 states that AGDC is a corporation "having a legal existence independent of and separate from the state," Treas. Reg. § 301.7701-1(a)(3) provides that AGDC's corporate status should not prevent AGDC from being treated as an integral part of the State for tax purposes:

an organization wholly owned by a State is not recognized as a separate entity for federal tax purposes if it is an integral part of the State.

Treasury Regulation § 301.7701-1(a)(3) indicates that the corporate separation of AGDC can be ignored for tax purposes if AGDC is an integral part of the State. The accompanying regulation, Treas. Reg. §301.7701-2(b)(1) & (6), seems to say that a corporation such as AGDC will, if it is not an integral part of the State, be taxed as a separate corporation.

For federal tax purposes, the term corporation means—(1) A business entity organized under a Federal or State statute, . . . if the statute describes or refers to the entity as incorporated or as a corporation, body corporate, or body politic; (6) A business entity wholly owned by a State or any political subdivision thereof . . .

Id.

Unfortunately Treas. Regs. §301.7701-1 & -2 provide no guidance regarding the circumstances that will cause a corporation wholly owned by a state or a political subdivision to be considered an integral part of the state. The Tax Court recently addressed whether a corporation organized under Delaware law was, analogous to Treas. Reg. § 301.7701-1(a)(3), an integral part of an Indian tribe and thus not exempt from federal taxation. *Uniband Inc. v. Comm'r*, 140 TC 13 (2013). The Tax Court in *Uniband* ultimately found that Uniband was organized as a state law business corporation and not under tribal law, that Uniband's constituent documents did not guarantee tribal control of Uniband, that Uniband appeared to have financial autonomy from the tribe, and held that Uniband was not an integral part of the tribe and was subject to federal taxation.

Private letter rulings addressing whether a corporation formed by a state, like AGDC, qualifies for federal tax exemption as an integral part of the state⁶ look to whether (a) there is sufficient state control over the entity and (b) whether the state has made a financial commitment to fund the corporation.

The State would control AGDC by controlling its board of directors, consisting of members appointed by, and serving at the pleasure of, the governor and subject to confirmation by the legislature and individuals designated by the governor that are each the head of a principal department of the State. AS 31.25.020.

The State would be making a substantial financial commitment to fund AGDC, and would be controlling its finances. First, as noted immediately above, the State would maintain board control of AGDC. AS 31.25.020. Second, the revised AS 31.25.110 provides that AGDC could only transfer revenues that it has received to an appropriate fund as determined by the commissioner of revenue in consultation with the commissioner of natural resources.

Recent private letter rulings holding that an enterprise or organization qualifies as an integral part of the state for tax purposes use the same analysis and cite substantially the same authorities, regardless whether the enterprise or organization was formed as a corporation. Namely, they each cite⁷ Rev. Rul. 87-2 as establishing that income earned by an enterprise that is controlled by the state and is an integral part of the state is not generally subject to federal taxation, and cite *Maryland Savings-Share Insurance Corp. v. United States*, 308 F.Supp. 761, *rev'd on other grounds*, 400 U.S. 4 (1970), for the proposition that, in order to qualify as an integral part of the state, the state must have made a sufficient financial commitment to the enterprise as well as maintained sufficient state control over the enterprise.⁸

⁶ A private letter ruling is only binding on the taxpayer(s) who requested the ruling; they are nonetheless a useful indication of how the IRS would rule on a specific transaction. The only published ruling in this area, Rev. Rul. 87-2, concerned a lawyer trust account fund created by order of the state supreme court that was not an independent entity. Taxpayers are entitled to rely on revenue rulings (such as Rev. Rul. 87-2), which are an official interpretations of the tax law on specific transactions published by the national office of the Internal Revenue Service.

⁷ Of the private letter rulings discussed immediately below, PLR 200403026 and 200427016 also cite Treas. Reg § 301.7701-1(a) as providing that an organization wholly owned by a state is not recognized as a separate entity for federal tax purposes if it is an integral part of the state.

⁸ Each of the private letter rulings listed immediately below also distinguishes *Michigan v. United States*, 802 F. Supp. 120, 127 (W.D. Mich. 1992), *rev'd*, 40 F. 3d 817 (6th Cir. 1994), which the Service believes is a flawed opinion that misapplied Rev. Rul. 57-128. (Professor Aprill also criticizes the *Michigan* opinion, concluding that "[i]n treating the trust as exempt, the majority confused and misapplied the tests for political subdivision, instrumentality, and integral part." 23 *Iowa J. Corp. L. at 825*.) While the *Michigan*

For instance, PLR 200403026 held that a hospital was as an integral part of a city for federal income tax purposes. The ruling found that the city had substantial control over the hospital (all of the members of the board were appointed by the mayor and subject to approval of the city commissioners; and the hospital's annual budget and audit were reviewed annually by the city commission). The ruling found that the city had made a substantial financial commitment to the hospital (the city contributed the hospital facilities and the land on which the facilities are located; and the city contributed cash and bond proceeds, including the proceeds from general obligation bonds, for the acquisition of additional land and the construction and renovation of the hospital facilities).

PLR 200136011 held that an authority, created by state statute to encourage commercial space flight from the state by promoting research and participating in the development of a commercial flight center, was as an integral part of the state for federal income tax purposes. The ruling found that the state had substantial control over the authority (of the authority's twelve directors, four were public officials and eight were appointed by the governor, subject to approval by both houses of the state legislature; the authority is required by statute to submit a detailed initial plan for the use of general funds appropriated for the authority to the governor and the state legislature, and the authority is required to submit an annual report and financial statement to the governor and the state legislature). The ruling also found that the state had made a substantial financial commitment to the authority by contributing moneys to the authority.

PLR 200427016 held that a non-profit public corporation, formed by the state legislature to operate insurance plans that function exclusively as residual market mechanisms to provide essential property insurance for residential and commercial property, was as an integral part of the state for federal income tax purposes. The ruling found that the state had substantial control over the corporation (the directors include public officials and their designees, and members appointed by the commissioner or governor, all senior management serve at the commissioner's pleasure, the corporation must file regular financial reports and its plan of operation must be approved by the department, the corporation's rates are specified by legislation, and all bonds and other indebtedness of the corporation must be approved by a state commissioner). The ruling also found that the state had made a substantial financial commitment to the corporation (by enacting legislation authorizing the corporation to collect the premium tax and to retain the proceeds of the premium tax to augment the corporation's resources).

analysis was recently adopted by the Tax Court in *Uniband Inc. v. Comm'r* (holding that a corporation organized under Delaware law was not an integral part of an Indian tribe), the Service's long-standing refusal to acquiesce in the *Michigan* opinion means that the Service likely will continue to issue private letter rulings that conform to its current ruling position based on Rev. Rul. 87-2 and *Maryland Savings-Share*, namely that State control and financial commitment are necessary to establish that an enterprise is an integral part of the State.

PLR 200827004 concerned whether an amendment to state law requiring additional assessments from insurers participating in the state insurance fund would alter the previous private letter ruling finding that the insurance fund was an integral part of the state for tax purposes. The ruling found that the state maintained board control over the fund as it had before, and that the amendment had not materially altered the state's financial commitment to the fund, and held that the fund maintained its status as an integral part of the state.

Reliance on AGDC being treated as an integral part of the State is problematic, however, as the IRS has not been consistent over the years in their rulings on whether a corporation formed under a state statute will be treated as an integral part of the state or its subdivisions. Enterprises that would seem to qualify as an integral part of a state or its political subdivisions sometimes receive rulings that they qualify for tax exemption under § 115(1), under which the IRS currently will only issue a favorable ruling based upon a showing of no private benefit.⁹

In sum, AGDC's qualification for tax exemption as an integral part of the State or its political subdivisions cannot be assured without a favorable private letter ruling.

III. Whether AGDC Qualifies as a Section 115 Entity.

If AGDC were not to qualify for tax exemption either under implied statutory immunity as a political subdivision of the State, or as an integral part of the State or its political subdivisions, the next question is whether AGDC qualifies for tax exemption under § 115.

Code § 115(1) provides that the income of AGDC would be excluded from federal taxation if it is derived from the exercise of any essential government function and accrues to the State or any of its political subdivisions.

In private letter rulings, the IRS not only examines the § 115(1) criteria of whether income is derived from the exercise of an essential government function and accrues to the state or its subdivisions but also considers whether private parties would benefit from the entity. The most recent published ruling regarding tax exemption under § 115 is Rev. Rul. 90-74. Revenue Ruling 90-74 held that the income of a nonprofit organization formed by county governments of the state to pool the casualty risks of the member-counties was excluded from income under §115(1), based upon findings that pooling casualty risks instead of purchasing commercial insurance constituted the exercise of an essential government function, that distribution of the assets of the organization upon dissolution to

⁹ E.g., PLR 8934052 (arts commission exempt under § 115, and not as integral part, because a state statute makes it a separate body "corporate and politic").

the member-counties satisfied accrual of income for purposes of § 115(1), and that private interests did not, "except for incidental benefits to employees of the participating state and political subdivisions, participate in or benefit from the organization."

Essential Government Function

For ruling purposes, the IRS tends to regard anything that makes or saves money for a political subdivision as an essential government function.¹⁰

it may be assumed that Congress did not desire in any way to restrict a State's participation in enterprises that might be useful in carrying out those projects desirable from the standpoint of the State government which, on a broad consideration of the question, may be the function of the sovereign to conduct.

Rev. Rul. 77-261. Revenue Ruling 77-261 held that a state investment fund, for the temporary investment of cash balances of the state and its political subdivisions, "constitutes the exercise of an essential governmental function for purposes of section 115(1) of the Code."

A recent private letter ruling with many similarities to the Project, PLR 200524015, found that a nonprofit corporation formed by political subdivisions of the state, consisting of natural gas and electric joint action agencies and distribution systems, qualified for exemption under § 115(1). The ruling specifically found that acquiring and financing long-term natural gas supplies, acquiring, constructing, owning, managing, operating and financing natural gas pipelines, liquefied natural gas facilities, storage and related facilities and equipment, and contracting with joint action agencies and public gas or power systems to provide them with natural gas supplies all constituted an essential governmental purpose within the meaning of § 115(1).

Accrual

In order to obtain a private letter ruling under § 115(1), an organization must show that it has satisfied the accrual test by including in its articles of organization a provision limiting distribution upon dissolution of all of AGDC's assets

¹⁰ April at 816. Note that there is very little contemporary authority that taxpayers are entitled to rely on, beyond the revenues rulings cited herein, for what constitutes "an essential governmental function" for purposes of §115(1). Case law is less than clear- the United States Supreme Court has concluded that it is essentially impossible to define what an essential governmental function is. The Supreme Court in *Garcia v. San Antonio Metropolitan Transit Authority*, 469 U.S. 528 (1985) concluded that "[t]here is not, and there cannot be, any unchanging line of demarcation between essential and non-essential governmental functions."

to one or more States, political subdivision(s) thereof, the District of Columbia, or to other organizations whose income is excluded from gross income under section 115(1).

Rev. Proc. 2003-12.

AGDC is a corporation specifically authorized by statute, AS 31.25. Alaska Statutes 31.25.010 provides that “[u]pon termination of [AGDC], its rights and property pass to the state.” which appears to comply with the ruling requirements of Rev. Proc. 2003–12.

Note that the courts have been less generous in their interpretation of what is required to satisfy the accrual requirement for tax exemption under § 115(1) than the ruling position of Rev. Proc. 2003-12,¹¹ which only requires disbursement of assets upon dissolution to the state or its political subdivisions to satisfy the accrual requirement. For instance, *City of Bethel v. U.S.*, 594 F.2d 1301 (9th Cir. 1979), *cert. denied*, 444 U.S. 980 (1979)¹² held that the mere accrual of income to a corporation owned by the governmental entity is not considered accrual to the governmental entity. The fact that the assets will revert to the state upon the corporation's dissolution, that the government was the sole owner of the corporation, or even that the state may request payment of profits at any time, did not qualify as direct accrual.

No Private Benefit

The IRS ruling position, that an entity cannot qualify for tax exemption under § 115 if it serves a private interest that is not incidental to the public interest, has no statutory basis. This requirement was apparently first asserted in PLR 8825027, the ruling that denied the Michigan Education Trust exemption under § 115 (a ruling that was effectively reversed by the Sixth Circuit in *Michigan v. United States*). *Id.* at n. 4.

To qualify under section 115, it must be established that the income does not serve private interests such as designated individuals, shareholders of organizations, or persons controlled, directly or indirectly, by such private interest. Thus, even if the income serves a public interest, the requirements of section 115 are not satisfied if the income also serves a private interest that is not incidental to the public interest. The basic principle underlying section 115 is that property (including any income thereon) must be devoted

¹¹ Rev. Proc. 2003-12 only addresses ruling requirements for a § 501(c)(3) organization that requests a ruling that it is also exempt under § 115(1), but likely reflects the Service's ruling position for an entity affiliated with a state that requests a ruling under § 115(1).

¹² The *City of Bethel* is a Ninth Circuit case, and is binding authority for AGDC.

to purposes which are considered beneficial to the community in general, rather than particular individuals.

PLR 8825027.

IRS rulings from the 1990s regarding state-sponsored disaster funds designed to deal with private insurance companies pulling out of the market for insuring certain forms of risk illustrate the risk that AGCD's involvement in the Project might be considered by the IRS to benefit private parties. For instance, the Florida and California private letter rulings, respectively PLR 9507037 and PLR 9622019, both found that the respective state disaster funds qualified for tax exemption as integral parts of their respective states, and concluded that, because the fund was an integral part, § 115 did not apply to the fund. Technical Advice Memorandum 94347001 reviewed another state's disaster fund and found that, besides failing to qualify as an integral part of the state or as a political subdivision of the state, the disaster fund also did not qualify for exemption under §115.

In declining exemption under §115, TAM 94347001 noted that "the sole purpose of [the fund] is to provide commercial-type insurance for private entrepreneurs," and specifically contrasted the fund with the risk pool at issue in Rev. Rul. 90-74, which pooled the risk exposure of political subdivisions of the state, and where private interests did not benefit more than incidentally. The disaster funds in Florida and California that received favorable rulings in PLR 9507037 and PLR 9622019 likely would not have qualified for exemption under §115 under the same analysis, as those disaster funds primarily benefited the private individuals seeking insurance coverage that they had not been able to obtain from the private insurance market. See Aprill at 828-830.¹³

AGDC's only owner will be the State or one of the State's political subdivisions. All distributions of AGDC are required by AS 31.25.110 to be distributed to an appropriate fund as determined by the commissioner of revenue in consultation with the commissioner of natural resources. While AS 31.25.110 is not clear on this point, the "appropriate fund" restriction seems intended to bar distributions from AGDC to anything other than a political subdivision or instrumentality of the State. The lack of clarity in what is an "appropriate fund" conceivably could be interpreted by the IRS as allowing the possibility of a private benefit from the fund.¹⁴

¹³ Also discussing the considerable congressional pressure that was applied by the delegation of California to ensure that California received and retained a favorable private letter ruling.

¹⁴ It is perhaps conceivable that the IRS could also find that the State's investment in, and ownership of, a minority interest in the Project, while providing additional royalty and tax revenue for the State and for the energy needs of the people of Alaska, could more than incidentally benefit the other investors in the Project.

It will be essential for the State to secure a favorable private letter ruling recognizing federal tax exemption under § 115 if AGDC intends to rely on exemption under that provision.

IV. Instrumentalities.

Alaska Statutes 31.25.010 states that AGDC is "a public corporation and government instrumentality . . ." (emphasis added). For tax purposes, an instrumentality is, by definition, an entity that is not a state or a political subdivision of a state. §§ 3121(b)(7)(F), 3306(c)(7) and 414(d); Rev. Rul. 57-128.

With the exception of certain corporations organized under an act of Congress as instrumentalities of the United States, status as an instrumentality does not indicate whether a corporation such as AGDC is exempt from federal taxation. Code § 501(c)(1) and Rev. Rul. 77-271. Revenue Ruling 77-261 concerned an investment fund established by a state treasurer that was "specifically designated as an instrumentality" of the state. After finding that the investment of funds was the exercise of an essential governmental function and after finding that the fund's income accrued to the state and the participating political subdivisions of the state, Rev. Rul. 77-271 held that income of the investment fund was exempt from federal income tax under §115(1).¹⁵

Designation as an instrumentality has significance for social security tax, federal unemployment tax and eligibility for governmental pension plans. §§ 3121(b)(7)(F), 3306(c)(7) and 414(d). The IRS analyzes whether an organization qualifies as an instrumentality for such purposes under the criteria set forth in Rev. Rul 57-128:

- (1) whether it is used for a governmental purpose and performs a governmental function;
- (2) whether performance of its function is on behalf of one or more states or political subdivisions;
- (3) whether there are any private interests involved, or whether the states or political subdivisions involved have the powers and interests of an owner;
- (4) whether control and supervision of the organization is vested in public authority or authorities;
- (5) if express or implied statutory or other authority is necessary for the creation and/or use of such an instrumentality, and whether such authority exists; and
- (6) the degree of financial autonomy and the source of its operating expenses.

If the IRS concluded that AGDC was an instrumentality, and not a political subdivision or an integral part of the State, it would examine whether AGDC qualified for

¹⁵ In other words, Rev. Rul. 77 - 261 held that the investment fund qualified for tax exemption under § 115(1); that holding was not based on the fund's status as an instrumentality of the state.

federal tax exemption under either § 115(1) (discussed above) or § 501(c), primarily § 501(c)(3) (discussed below). Aprill at 821.

If AGDC is considered an instrumentality of the State, it will be essential for the State to secure a favorable private letter ruling recognizing federal tax exemption under § 115 if AGDC does not qualify for exemption as a political subdivision of the State or as an integral part of the State.

V. § 501(c)(3) Organizations.

AGDC, as a “public corporation and instrumentality” of the State could qualify for exemption under §501(c)(3) if it were a “clear counterpart” of a charitable, educational, religious or like organization. Rev. Rul. 60–384; see also Rev. Rul. 55–319. There is at least an issue whether the IRS would consider AGDC, investing in a liquefied natural gas Project, to be a “clear counterpart” of a charitable organization.

Further, if AGDC is an integral part of the State, which it would seem to be if it does not qualify a political subdivision, it would not qualify for exemption under §501(c)(3). Revenue Ruling 60-384 ruled that because a state's purposes include those not exclusively described in § 501(c)(3), an organization that is an integral part of the state cannot meet the requirements for exemption under § 501(c)(3).

Finally, if AGDC's powers exceed the scope of those allowed by § 501(c)(3), AGDC would not qualify for exemption under § 501(c)(3). Rev. Rul. 60-384. AGDC's regulatory powers, discussed above, appear to disqualify AGDC as a § 501(c)(3) organization. Id. In Rev. Rul. 74–14, a public housing authority was denied exemption under § 501(c)(3), even though its purpose was to provide safe housing accommodations for low income families, because the state statute incorporating the authority gave it the power to conduct examinations and investigations for the purpose of collecting information and making it available to appropriate agencies for use in furthering and enforcing local ordinances regarding planning, building, and zoning matters. Revenue Ruling 74–14 concluded this power to conduct examinations and investigations was a regulatory power that was inconsistent with exemption under § 501(c)(3).

For reasons such as those set forth above, § 501(c)(3) seems the least likely ground for AGDC to qualify for federal tax exemption.

VI. Conclusion.

The State is strongly recommended to secure a private letter ruling confirming that AGDC qualifies for tax exemption at the earliest opportunity, as AGDC's involvement in the Project will require substantial State investment. If SB 138 and HB 277 are enacted into law, the ruling request should be made shortly thereafter.

In order to facilitate securing a favorable ruling, the Committee is also advised to incorporate the changes discussed in principle at page 8 of this letter into SB 138 and HB 277, to better establish that AGDC's qualifies for implied statutory immunity as a political subdivision of the State.

Notice Regarding Tax Advice

We hope that this letter helps explain the federal tax exemption issues raised by the Project and the related pending legislation. We would be happy to expand upon our analysis should the Committee or the Legislature so desire or to address any particular questions that the Committee or the Legislature may have.

This letter has been prepared solely for use by the State, the Legislative Budget & Audit Committee, and the Alaska state legislature. Any tax advice contained in this letter was not intended or written to be used, and cannot be used, for the purpose of (i) avoiding tax-related penalties under the Internal Revenue Code, or (ii) promoting, marketing, or recommending to another party any transaction or matter addressed herein.

The advice in this letter is not binding on the Internal Revenue Service, any court, or any other person or entity. The Internal Revenue Code has been subject to substantial and frequent revisions in recent years. We cannot assure that forthcoming IRS interpretations, administrative pronouncements, or court decisions will not adversely affect the tax advice given in this letter.

Realization of federal tax exemption is subject to the risk that the Internal Revenue Service may challenge tax treatment and that a court may sustain that challenge. Because taxpayers carry part of the burden of proof required to support the tax treatment of a transaction, the advice expressed as to the likelihood of realization of federal tax exemption assumes that you will undertake the effort and expense to request an appropriate private letter ruling and present fully the State's case in support of any matter that the Service challenges.

Sincerely,

MANLEY & BRAUTIGAM, P.C.

By:


Charles F. Schuetze

Comments provided by Larry Persily, Federal Pipeline Coordinator

At the Request of House Resources Co-Chair Eric Feige – March 31, 2014

"I looked over the thoughtful and detailed questions that Rogers Marks submitted to the committee and offer my observations/comments to some below (those with federal issues or where I have knowledge from my work as Federal Coordinator or my past role as deputy commissioner at Revenue)"

FOR THE PRODUCERS

1. How would you feel about a provision in the legislation that in exchange for taking the taxes and royalties as in-kind gas, the producers would agree to purchase and dispose of the state's gas at the same price that the producers receive for the rest of their gas, just as is done with in-value now? The problem is that not all LNG is sold at the same price or on the same terms — each contract is different. Pricing can be different, not just the percentage linkage to oil prices but caps at the low end and high end and "softening" of the linkage curve at high oil prices; the number of years; volume flexibility and destination flexibility; peak deliverability (such as extra gas in the winter); shipping (does the seller or buyer arrange for shipping); and on and on. It's just not the same as for oil, where there is pretty much a daily price for all oil cargoes or a certain quality.) It would be difficult for the state to demand — or want — the same contract terms as the producers with every LNG buyer in every transaction. I'd expect the gas from Alaska LNG could be sold off to a dozen or more different buyers, all with different contracts. Besides, the state may very well want different contract terms with LNG buyers than the producers. Maybe there would be a choice between a higher price with a buyer's option to reduce volume in certain circumstances vs. a lower price and a 100% lock on 100% of the volume with no flexibility. Which should the state select? Protection against below-market contracts is a good idea, and I would expect the state could write into its marketing services RFP a provision ensuring disclosure of other contracts for sake of comparison.

2. Are there any precedents under FERC Section 3 regulation where there are large pipelines with local consumption of transported gas? The only pipelines covered by FERC under Sec. 3 of the Natural Gas Act would be pipelines that exclusively serve an LNG plant, as opposed to a Sec. 7 interstate line that also happens to feed an LNG plant. As such, when you think about Lower 48 LNG plants, the pipelines to the plants either already existed in the area (think U.S. Gulf Coast) and therefore were Sec. 7 rate-regulated lines serving interstate and intrastate customers, or they are short new spurs to the LNG plant. Those short spurs, however, also are most likely part of the interstate pipeline network, carrying interstate gas to the plant. Which is a long way of saying I doubt whether there are any large Sec. 3 pipelines that carry gas only to and from an LNG plant and limited local (in-state) buyers/sellers, thereby escaping Sec. 7 FERC rate regulation. I believe there could be some very short spurs that serve only an LNG plant and no one else, which would be covered by Sec. 3, which would mean a FERC-led environmental impact statement and authorization for construction and operation, but not Sec. 7 interstate rate regulation. The Alaska LNG project is different from anything else in the Lower 48.

FOR THE ADMINISTRATION

1. How would you feel about a provision in the legislation that in exchange for taking the taxes and royalties as in-kind gas, the producers would agree to purchase and dispose of the state's gas at the same price that the producers receive for the rest of their gas, just as is done with in-value now? Same answer as above.

FOR AGDC

3. What is the possibility of 100% state debt financing through revenue bonds and general obligation bonds? 1) I doubt the state has the debt capacity for that much in general obligation bonds, though I admit the rate would be less than a commercial loan if the state could actually float that massive of a bond issue; 2) And even if you could get 100% general obligation debt, any shortcoming in covering the debt in any given year from project revenues would require a politically painful direct draw on the general fund that year; 3) I am not aware of an LNG import or export project anywhere in the world financed with 100% project revenue debt (lenders have always wanted a hefty down payment on LNG projects), and I see no reason why Alaska LNG would be any different (actually, lenders might want a heftier down payment because of the perceived political risk in Alaska oil and gas politics); 4) Some lenders through the years have pitched the tantalizing prospect of 100% project revenue debt financing to the state, but I believe they have done so to entice business through their door (no offense meant to their marketing efforts).

4. What is the possibility of getting tax-exempt debt through the Alaska Railroad? I wonder how lenders would react to a scheme to use the railroad (with its own financial challenges) as a front to get tax-exempt financing to beat the IRS, when the railroad has not a dime of its own in the venture. Besides, when this idea was floated last decade, the railroad wanted a fee to serve as the front, something in the neighborhood of 0.75% — nothing is free. This entire discussion goes back a decade, when state officials realized the federal law that transferred the railroad to the state included a provision allowing the railroad to issue tax-exempt debt — but the law offers no specifics or guidance. Many state officials thought it would be a tough sell to get the IRS to go along with a multibillion-dollar tax-exempt bond sale for what is essentially a business venture (as opposed to a public-purpose development, such as a passenger train terminal). Senate Finance Co-Chair John Torgerson went out and paid for a legal opinion on the railroad debt issue (about 12 years ago). Perhaps he still has a copy? Note: People point to the tax-exempt bonds issued by the City of Valdez for the Alyeska oil terminal in the 1970s. True, that worked, but the law was later changed and you cannot do that again. (I also see that the railroad has gone out with an RFP to contract for a financial adviser to look at just such a venture. See http://alaskarailroad.com/LinkClick.aspx?fileticket=j_g9BuNzdSY%3D&tabid=408)

FOR TRANSCANADA

2. Are there instance in the pipeline business where pipeline companies absorb some pre-development costs if the project is not sanctioned? Yes, happens all the time.

FOR INVESTORS/BANKS

1. Would commercial or investment banks, private equity firms, or venture capital firms be interested in investing with the state as a partner? What rate of return would be necessary? No one will give you a firm interest rate quote until they see the total project; that's what FEED is to accomplish. It all depends on the project, the developer's balance sheet and the sales contracts. For example, Cheniere Energy needed cash for construction of its Sabine Pass, La., LNG export terminal. It raised much of its equity share by agreeing to pay 17% to a private-equity firm to help raise the 30% equity (down payment) required to borrow the other 70% of the money for construction.

2. What is the possibility of 100% state debt financing through revenue bonds and general obligation bonds? See above.

3. What is the possibility of getting tax-exempt debt through the Alaska Railroad? See above.

FOR FEREC

1. Would FEREC be comfortable regulating this project under Section 3 of the Natural Gas Act? FEREC will not say anything until it has an actual application on its desk. But whether it is "comfortable" is not the issue; LNG plants are regulated by Sec. 3 – of the Natural Gas Act, there is no option. FEREC has worked with Sec. 3 for years, and is familiar and comfortable with its job. Pipelines that serve an LNG plant can fall under Sec. 3; it's up to FEREC. And since there is no interstate component to the Alaska LNG pipeline project as currently proposed, I believe FEREC would lump the pipeline and the LNG plant into one environmental impact statement for health and safety and environmental concerns, which is the focus of Sec. 3. I also expect a project developer would want a single federal EIS by a single federal agency, rather than separate impact statements and separate timetables for the pipeline and LNG plant. As to pipeline tariffs, without an interstate component to the pipeline, there is no jurisdictional hook and no Sec. 7 tariff regulation by FEREC. It's not a matter whether FEREC is "comfortable" with that — it's the law.

FOR THE ENERGY DEPARTMENT

1. Would DOE revoke the LNG export permit if the gas were needed for in-state consumption? Please describe how that process would work. There is no formal process because it's never ever happened in the United States. Remember, until a couple of years ago, no one had ever tried to build an LNG export plant in the Lower 48 -- the only one was in Nikiski. Federal law allows the Department of Energy to suspend or revoke an export license, no question about the authority. In response to a question from Sen. Murkowski, the department in October 2013 wrote: "The Department takes very seriously the investment-backed expectations of private parties subject to its regulatory jurisdiction. As we have stated consistently, DOE would not rescind a previously-granted (export) authorization except in the event of extraordinary circumstances. ..." Besides, even if in-state need for North Slope gas increased, it likely would be such a small percentage (single digit) of the overall project that I believe one (or more) of the pipeline partners likely could fit that additional gas into the line for local off-takes. The better question would be to the Alaska LNG partners: How much additional gas could you fit into the pipeline for in-state off-takes by adding compression before you would need to add actual pipe?

**Testimony of Charlotte Brower
Mayor, North Slope Borough, Alaska
April 1, 2014**

**Before the
House Resources Committee
Alaska State Legislature
Legislative Hearing on SB138**

Good morning Co-chairman Feige, Co-chairman Saddler, and members of the House Resources Committee.

My name is Charlotte Brower. I am the Mayor of the North Slope Borough. This is the second time I've testified before you this session, so you already know how proud I am to be the wife of a whaling captain with six children and twenty-five grandchildren.

Thank you for the opportunity to speak on SB138, a bill that authorizes the State of Alaska to move forward on developing a natural gas pipeline from the North Slope to tidewater.

Today I would like to talk about some of the concerns and interests of the North Slope Borough regarding SB 138 and the Heads of Agreement, which is a separate document that outlines the guiding principles of the Alaska LNG Project.

Before we talk about concerns, its important that say 'Thank You' to our Good Lord for the opportunity to be having this discussion on how to build a 60 billion-dollar project to develop our natural gas. There's a lot of people who would love to have something like this on the table.

Please let me take a moment to acknowledge our appreciation for your efforts on behalf of our residents. You are truly deciding the future of our state, and on behalf of the North Slope Borough, I commend you. Quyanaqpak.

As Alaskans, we've learned from the past that large projects like this can set a positive course for our future. But we also know that in order to provide the maximum possible benefits, we have to be prepared for the impacts. For example, the Trans Alaska Oil Pipeline has provided billions of dollars of revenue and jobs, but we also learned lessons about demands for public services to deal with social services, job training, infrastructure, public safety, and education.

That brings me to the points that should be addressed in Senate Bill 138 and the Heads of Agreement document before this committee.

The Heads of Agreement has language in Article 9.3 that states the “Parties” intend for the project’s fiscal terms to be included in project-enabling contracts. Subject to “consultation” with local governments, the Administration will establish payments in lieu of property tax (PILT).

The word “consultation” is not defined in the HOA document, but I would like to acknowledge Governor Parnell for signing an Administrative Order that establishes a municipal advisory group.

At some point in the future, we see that the process for enabling contracts is an “up or down” ratification vote by the Legislature after the Administration submits them to you for approval. If the local taxing authority of municipal governments is going to be modified to provide fiscal certainty, then we must be a meaningful part of the process up front.

The second issue that has been discussed amongst the mayors has been whether the enabling contracts will be used to reclassify properties that are currently taxable under AS 43.56. This is the state law regarding property taxes on oil & gas infrastructure.

This is one of those issues where we don't know if this should be a concern. But no one has told us that we shouldn't be concerned. Perhaps there's a good reason why these current properties aren't specifically excluded from the provisions of SB138. Until there's something that explains this issue, as municipal governments we must speak up to protect our current tax base. That's the point I want to put on the record today.

The last time I testified before the House Resources Committee, I spoke in support of HJR26. HJR26 is a resolution calling upon the United States Congress to pass legislation that establish a revenue sharing program from the proceeds of oil and gas development on the outer continental shelf off our shores. Thank you to Co-chair Saddler and all of your for helping get this resolution passed. By working together as Alaskans, we are sending a message for receiving a fair and equitable distribution of revenues that come from energy development off our shores.

It was our combined message as state and local governments that we will need resources to keep up with infrastructure requirements, expand emergency response and search and rescue capabilities, and work to maintain healthy communities and a healthy ecosystem.

When it comes to dealing with the impacts of oil and gas development, the basic discussion between offshore and onshore is not really that much different. As the local government responsible for providing basic essential services, the North Slope Borough is there to help provide for cost of schools, emergency response, health and social services, and public safety.

Like most other municipal governments, the North Slope Borough relies upon our authority to levy a property tax in order to generate the revenue to provide these public services. That is why any discussion to exempt property taxes from a project of this magnitude gives me cause for concern.

This is not the first time we've discussed the development of a natural gas pipeline and the issue of fiscal stability for the project. And I continue to believe that municipal taxes are not the issue that makes or breaks the margin on a project that could exceed \$50 billion.

No one wants to see a natural gas pipeline more than myself. I see the opportunity for my grandchildren to have good jobs, and I also want to see access to affordable energy for my grandchildren's children.

In order to get jobs and access to affordable energy, our villages will need good schools, housing, and other basic services in order to take advantage of the opportunities. And for that reason, I am here today to speak up for the ability of our municipal government to have the authority to meet those needs.

Quyanaqpak



**Alaska House Resources Committee Testimony
April 1, 2014**

Mr. Chairman and members of the Committee:

Thank you for providing this opportunity to express our concerns about the impacts that pending fiscal negotiations for a gas pipeline project might have on our municipalities if SB138 passes as currently drafted.

The recent Heads of Agreement between the State and the North Slope Producers lays the framework for future negotiation of fiscal terms for an Alaska LNG project which includes enactment of the enabling legislation now before you. This Heads of Agreement provides that the State and North Slope producers will negotiate a payment in lieu of taxes "PILT", which would eliminate property taxes during the operating life of a project. The agreement also provides that the Producers would pay pre-negotiated impact fees during construction, rather than property taxes as currently required under Alaska law.

The Heads of Agreement also states that one of its purposes is to reduce valuation disputes between the parties, and to ensure a healthy long-term OIL business. We are therefore worried that these yet to be negotiated gasline terms might expand to alter property taxes paid on existing infrastructure as well, including that used in oil exploration, production, and transportation.

We have been verbally assured by the Administration and by some members of the Legislature that it is not anybody's intention to change the taxing regime on existing infrastructure as part of these upcoming negotiations. However, we find these non-binding assurances to be something less than comforting.

We still believe our concerns in this area to be well founded. The only other time the Producers have ever come to consensus regarding fiscal terms to build a gasline was during the Murkowski Administration, under the Governor's

Stranded Gas Development Act (SGDA) contract. That contract required PILT payments on both new gas infrastructure **AND** existing oil infrastructure, in order to get the Producers to take the next step which was merely another study. Had the SDGA been adopted, we would have gotten that study, without ever seeing an actual pipeline; yet local governments would today be receiving only a fraction of the tax revenues that are currently being generated under existing law.

Like the SGDA, the recent Heads of Agreement only pursues another study, and is clearly heading in this same direction regarding fiscal terms. We therefore believe it to be unrealistic to think that history would not repeat itself, and that the Producers would not put existing tax structures on the table, despite the State's best intentions, once everyone got behind closed doors for these confidential negotiations.

The City of Valdez receives over 90% of our operating revenues from this existing property tax structure. This is appropriate due to the demands of the very infrastructure being taxed. For example, as a result of TAPS infrastructure within our municipality, the City of Valdez is required to provide a much greater level of municipal services than would otherwise be required of a community our size; especially in the areas of fire fighting, security, and public works. Significant reductions to this revenue, like that negotiated under the SDGA, would have a catastrophic impact on the City's ability to continue meeting the needs of Alyeska; and more importantly, our ability to honor existing bond obligations, or even to continue providing the most basic public services to our residents.

Therefore, to address these concerns we seek your help in achieving the following goals:

- 1) **Protecting Property Taxes on Existing Oil and Gas Property** – We request that this enabling legislation be amended to provide clear intent that the Legislature would look unfavorably on any future agreement brought back to it that goes backwards and takes away what is already being provided to the state and/or the municipalities under existing law.
- 2) **Property Taxes During Construction of an LNG Project** - Alaskan municipalities must be able to analyze all the details of the project plan, before they can properly measure the impacts construction will have on their communities. Each affected municipality needs to discuss, negotiate and agree to terms that directly affect impacts a project like this would have on municipal budgets, and the extent shortfalls would have to be made up by other tax payers. Again, legislative input now, emphasizing a meaningful role for affected municipalities is critical.

- 3) **Property Taxes During Operation of an LNG Project** - Property tax concessions for new infrastructure may very well be appropriate to facilitate project development. We all recognize this and want to do all we can to help facilitate a project. However, before such an agreement could be possible, the economics need to be well defined to enable a determination of the extent to which an Alaska LNG project, once in operation, should pay property taxes at a rate less than other property owners. Only after project economics are well understood can the need for and magnitude of a PILT be properly analyzed. As with negotiations related to impact fees during construction, meaningful municipal participation in the development of these terms is essential. Only the municipalities themselves, not the state negotiating on their behalf, can truly assess local impacts.

We do understand that the more involvement there is in any process, the more complex the task becomes. But it's important to remember that complexity is the price we've always needed to pay for meaningful participatory government.

We have suggested amendment language to help address some of these concerns and would appreciate your serious consideration to support these concepts or substantially similar safeguards. If the North Slope producers are allowed an open ended, confidential process like that used with Governor Murkowski, the financial consequences to municipalities would likely be extreme. Enacting safeguards into this legislation to address these concerns now is a necessary step to ensure that does not happen.

Again, thank you very much for your consideration.

David Cobb
Mayor of Valdez



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

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: | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | |
|---------|--|-----------------------------------|--|--|------------------------------------|---------------------------|--------------------------------|---|---|---|--|---|---|----------------------------------|--------|
| COLUMN: | B | C | D | E | F | G | H | I | J | K | L | M | N | O | |
| | Pre-Expansion Capital Cost Share | Pre- Expansion Capital Cost | Pre-Expansion 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 | |
| 5 | | | | | | | | | | | | | | | |
| 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 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/\$L10 | =J6/\$J10 |
| 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/\$L10 | =J7/\$J10 |
| 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/\$L10 | =J8/\$J10 |
| 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/\$L10 | =J9/\$J10 |
| Total | =SUM(D6:D9) | 100 | 25 | =C10/D10 | =SUM(F6:F9) | 10 | 5 | =G10/H10 | =D5+H5 | H10 | =J10*K10 | =SUM(M6:M9) | =SUM(N6:N9) | =SUM(O6:O9) |

The Honorable Geran Tarr

March 21, 2014

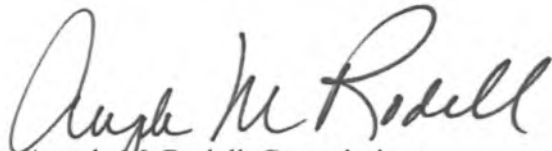
Page 13

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

QUESTIONS - SB 138

Questions for Producers

1. How would you feel about a provision in the legislation that in exchange for taking the taxes and royalties as in-kind gas, the producers would agree to purchase and dispose of the state's gas at the same price that the producers receive for the rest of their gas, just as is done with in-value now?
2. Are there any precedents under FERC Section 3 regulation where there are large pipelines with local consumption of transported gas?
3. With no transparent pipeline tariffs, do you see a concern for future small gas producers on the North Slope who may want to dispose of their gas at a fair price with the large producers as is done currently with oil?
4. Once the project is up and running, if there is an increase in in-state demand that requires production of more gas, how do you envision that process happening?
5. In the absence of regulation, if there is an increase in production to accommodate increased in-state demand, and gas is being sold from the producers to Alaskans, how do you envision Alaskans getting such gas at reasonable prices? If the price is based on netback pricing, how will a reasonable transportation deduction be ensured? How would you feel about a provision in the statute ensuring reasonable terms?
6. Could the producers provide, for a fee, technical assistance in expanding the facilities?
7. Is it possible the sponsors could go through the whole pre-FEED and FEED processes, spend \$2.2 billion, get to FID, and not sanction the project?
8. What other oil and gas projects around the world is the potential capital for this project competing with in your portfolios?
9. What other places around the world where you do business does the government share in spending in planning costs?
9. What are the government takes in jurisdictions where governments share the failure to sanction risk with the oil companies?
10. If you believe this project can compete in the market, what would be the risk to you of the state holding off investing in the project until it is sanctioned?
11. Wouldn't it give the producers the long-run alignment they need by having the state buy into the project once it is sanctioned (paying their share of pre-development costs, with interest)?

12. What percentage of the pre-FEED and FEED costs will be paid for by the state and federal government through income tax deductions?

13. What will constitute sufficient fiscal certainty for the producers? Wouldn't it make sense to have this established before the state incurs the cost of pre-FEED, in case there is a later impasse?

14. When your company takes out a firm transportation commitment for pipeline capacity, does it impact your debt capacity?

Questions for Administration

1. How would you feel about a provision in the legislation that in exchange for taking the taxes and royalties as in-kind gas, the producers would agree to purchase and dispose of the state's gas at the same price that the producers receive for the rest of their gas, just as is done with in-value now?

2. With no transparent pipeline tariffs, do you see a concern for future small gas producers on the North Slope who may want to dispose of their gas at a fair price with the large producers as is done currently with oil?

3. Once the project is up and running, if there is an increase in in-state demand that requires production of more gas, how do you envision that process happening?

4. How would you feel about an amendment in the legislation compelling producers to produce more if in-state demand increases?

5. In the absence of regulation, if there is an increase in production to accommodate increased in-state demand, and gas is being sold from the producers to Alaskans, how do you envision Alaskans getting such gas at reasonable prices? If the price is based on netback pricing, how will a reasonable transportation deduction be ensured? How would you feel about a provision in the statute ensuring reasonable terms?

6. In terms of limits on the state's debt capacity, what is the difference between incurring debt to own a given portion of the project, and incurring debt through a firm transportation commitment to TransCanada for the same portion to ship the in-kind gas? If there is no difference, and the limit exists, how can the state take the gas in-kind?

7. Is it possible the sponsors could go through the whole pre-FEED and FEED processes, spend \$2.2 billion, get to FID, and not sanction the project?

8. Wouldn't it give the producers the long-run alignment they need by having the state buy into the project once it is sanctioned (paying their share of pre-development costs, with interest)?

9. What will constitute sufficient fiscal certainty for the producers? Wouldn't it make sense to have this established before the state incurs the cost of pre-FEED, in case there is a later impasse?
10. Wouldn't it make sense for the state to wait at least until pre-FEED is over to exercise the ownership option, in order to have full information, rather than by December 31, 2015 if pre-FEED is not completed by then?
11. Why would the state want to execute a firm transportation services agreement before FEED? Is this customary? Isn't there insufficient information at that point to warrant making the commitment?
12. How much of this proposal was designed around giving TransCanada a material role in order to avoid a potential treble damage claim under AS 43.90.440 of AGIA?
13. If the state were to own the entire 25% of the facilities, at a \$45 billion cost, that would be \$11 billion in today's dollars. If the state financed this with 75% debt and 25% equity, this would only be \$2.81 billion in equity it would have to come up with. Would it be possible for the Permanent Fund to invest this amount at a lower return on equity than what TransCanada is commanding, say 11%? Isn't 11% greater than the Permanent Fund's long-run average return on equity?

Questions for AGDC

1. How much expertise in financing, building, and operating pipelines and treatment plants does AGDC envision having should the ASAP project come to fruition? Does AGDC envision having a partner for expertise? Contractors?
2. Does AGDC envision having a partner to build and operate the state's 25% share of the LNG facility? Contractors?
3. What is the possibility of 100% state debt financing through revenue bonds and general obligation bonds?
4. What is the possibility of getting tax-exempt debt through the Alaska Railroad?

Questions for TransCanada

1. What is TransCanada's experience in gas treatment?
2. Are there instance in the pipeline business where pipeline companies absorb some pre-development costs if the project is not sanctioned?

3. Do TransCanada's bonds generally have a callable feature such that if interest rates go down it can refinance?
4. Wouldn't it make sense for the state to wait at least until pre-FEED is over to exercise the ownership option, in order to have full information, rather than by December 31, 2015 if pre-FEED is not completed by then?
5. Is it customary for your customers to execute firm transportation service agreements as early as before FEED?
6. How do you interpret the license project assurances clause (AS 43.90.440) in AGIA?

Questions for Leg Legal

1. If the state were to proceed in a project without TransCanada - modify taxes, have some ownership, acquire a partner - what would be the risk of legal and financial exposure under the license project assurances clause (AS 43.90.440) in AGIA?
2. How do you interpret "total amount" in the clause? "grant of state money"? "preferential royalty or tax treatment"?

Questions for Department of Law

1. If the state were to proceed in a project without TransCanada - modify taxes, have some ownership, acquire a partner - what would be the risk of legal and financial exposure under the license project assurances clause (AS 43.90.440) in AGIA?
2. How do you interpret "total amount" in the clause? "grant of state money"? "preferential royalty or tax treatment"?

Questions for an Outside Commercial or Investment Banks or Private Equity Firms

1. Would commercial or investment banks, private equity firms, or venture capital firms be interested in investing with the state as a partner? What rate of return would be necessary?
2. What is the possibility of 100% state debt financing through revenue bonds and general obligation bonds?
3. What is the possibility of getting tax-exempt debt through the Alaska Railroad?

Questions for FERC

1. Would FERC be comfortable regulating this project under Section 3 of the Natural Gas Act?

Questions for Department of Energy

1. Would DOE revoke the LNG export permit if the gas were needed for in-state consumption?
Please describe how that process would work.

**Questions prepared by LB & A Consultant – Roger Marks
March 31, 2014**



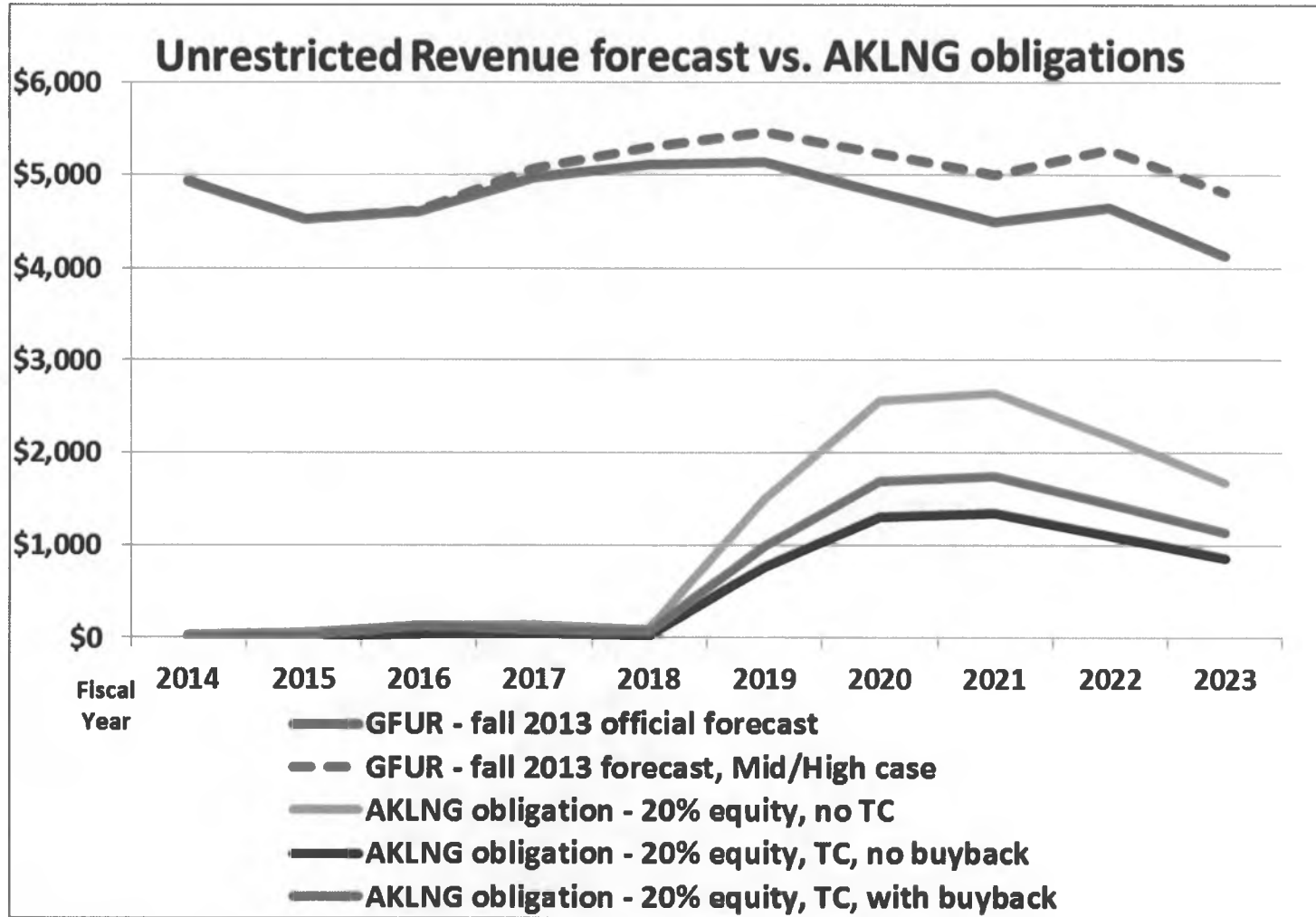
AK LNG: Potential State Revenues and Debt Capacity

**Supplemental Slides in response to request
from Rep. Tarr
March 21, 2014**

Alaska Department of Revenue



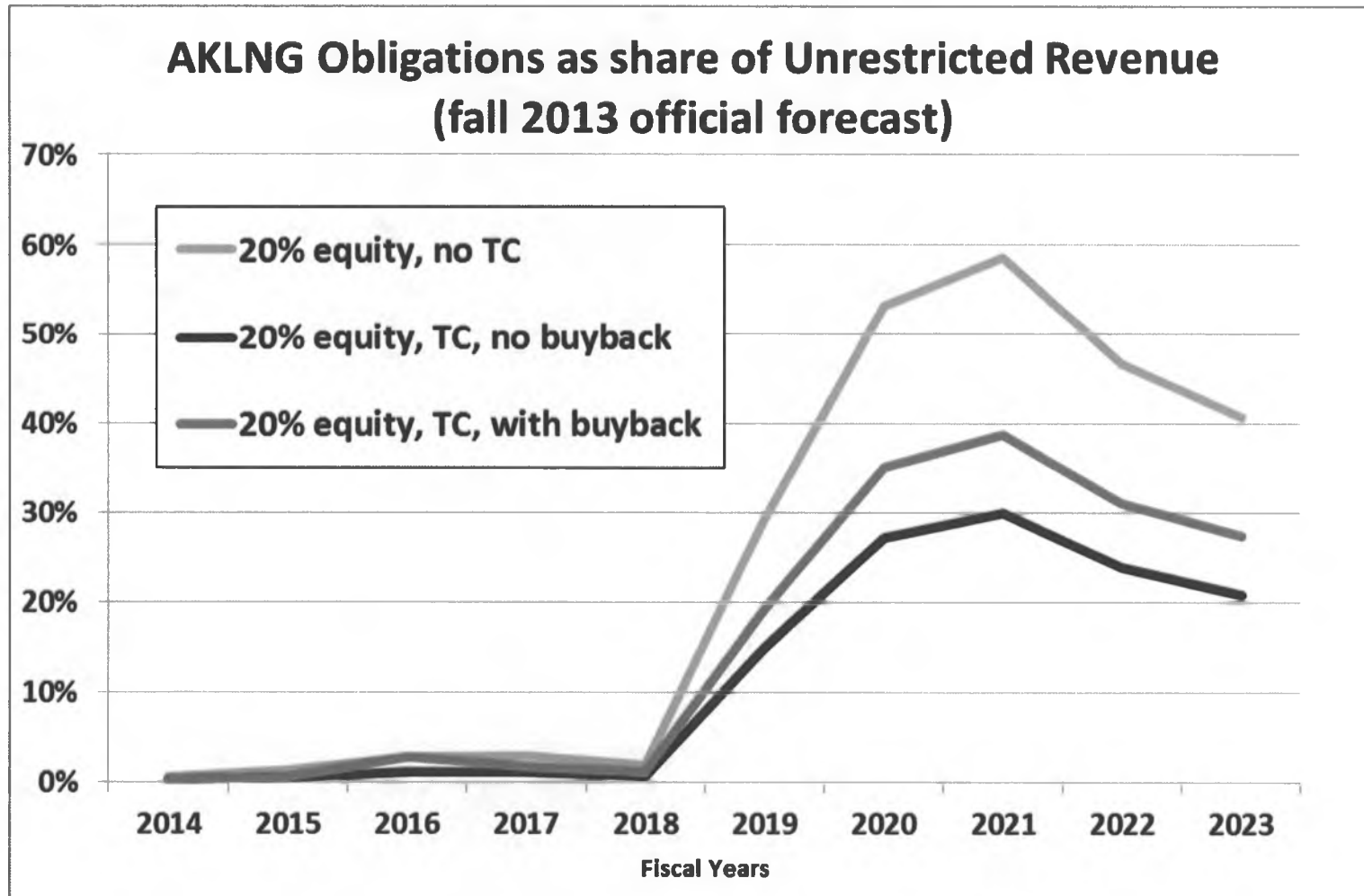
REVENUE FORECAST VS AKLNG OBLIGATIONS @ 20% STATE OWNERSHIP IN MILLIONS OF DOLLARS



Source: Department of Revenue - Revenue Sources Book Fall 2013; Black and Veatch.

Assumes obligation is due in the corresponding fiscal year; i.e. CY 2019 obligation in FY 2019, etc.

AKLNG OBLIGATIONS VS. GFUR FORECAST @ 20% STATE OWNERSHIP



Source: Department of Revenue - Revenue Sources Book Fall 2013; Black and Veatch.

Assumes obligation is due in the corresponding fiscal year; i.e. CY 2019 obligation in FY 2019, etc.

AKLNG OBLIGATIONS VS. GFUR FORECAST @ 20% STATE OWNERSHIP IN BILLIONS OF DOLLARS.

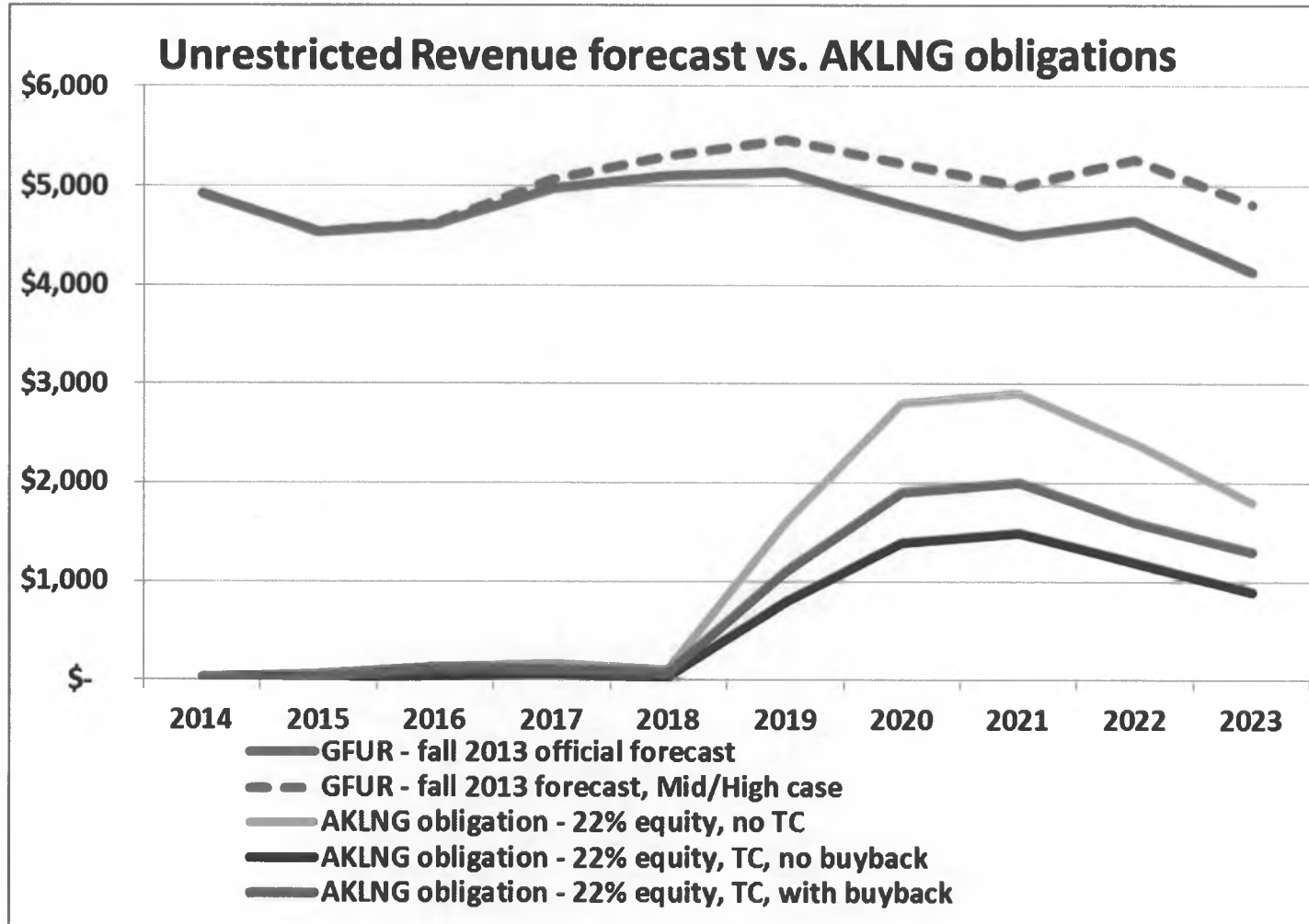
Unrestricted Revenue Forecast vs. AKLNG Obligations

| | FY 2014 | FY 2015 | FY 2016 | FY 2017 | FY 2018 | FY 2019 | FY 2020 | FY 2021 | FY 2022 | FY 2023 |
|--|---------|---------|---------|---------|---------|---------|---------|---------|---------|---------|
| GFUR - fall 2013 official forecast \$billions | \$ 4.9 | \$ 4.5 | \$ 4.6 | \$ 5.0 | \$ 5.1 | \$ 5.1 | \$ 4.8 | \$ 4.5 | \$ 4.7 | \$ 4.1 |
| GFUR - fall 2013 forecast, Mid/High case \$billions | \$ 4.9 | \$ 4.5 | \$ 4.6 | \$ 5.1 | \$ 5.3 | \$ 5.5 | \$ 5.2 | \$ 5.0 | \$ 5.3 | \$ 4.8 |
| AKLNG obligation - 20% equity, no TC \$billions | \$ 0.0 | \$ 0.1 | \$ 0.1 | \$ 0.1 | \$ 0.1 | \$ 1.5 | \$ 2.6 | \$ 2.6 | \$ 2.2 | \$ 1.7 |
| AKLNG obligation - 20% equity, TC, no buyback \$billions | \$ 0.0 | \$ 0.0 | \$ 0.1 | \$ 0.1 | \$ 0.0 | \$ 0.8 | \$ 1.3 | \$ 1.3 | \$ 1.1 | \$ 0.9 |
| AKLNG obligation - 20% equity, TC, with buyback \$billions | \$ 0.0 | \$ 0.0 | \$ 0.1 | \$ 0.1 | \$ 0.1 | \$ 1.0 | \$ 1.7 | \$ 1.7 | \$ 1.4 | \$ 1.1 |
| Obligation % of GFUR - 20% equity, no TC | 1% | 1% | 3% | 3% | 2% | 29% | 54% | 58% | 47% | 41% |
| Obligation % of GFUR - 20% equity, TC, no buyback | 0% | 1% | 1% | 1% | 1% | 16% | 27% | 29% | 24% | 22% |
| Obligation % of GFUR - 20% equity, TC, with buyback | 0% | 1% | 2% | 2% | 1% | 19% | 35% | 38% | 30% | 27% |

Source: Department of Revenue - Revenue Sources Book Fall 2013; Black and Veatch.

Assumes obligation is due in the corresponding fiscal year; i.e. CY 2019 obligation in FY 2019, etc.

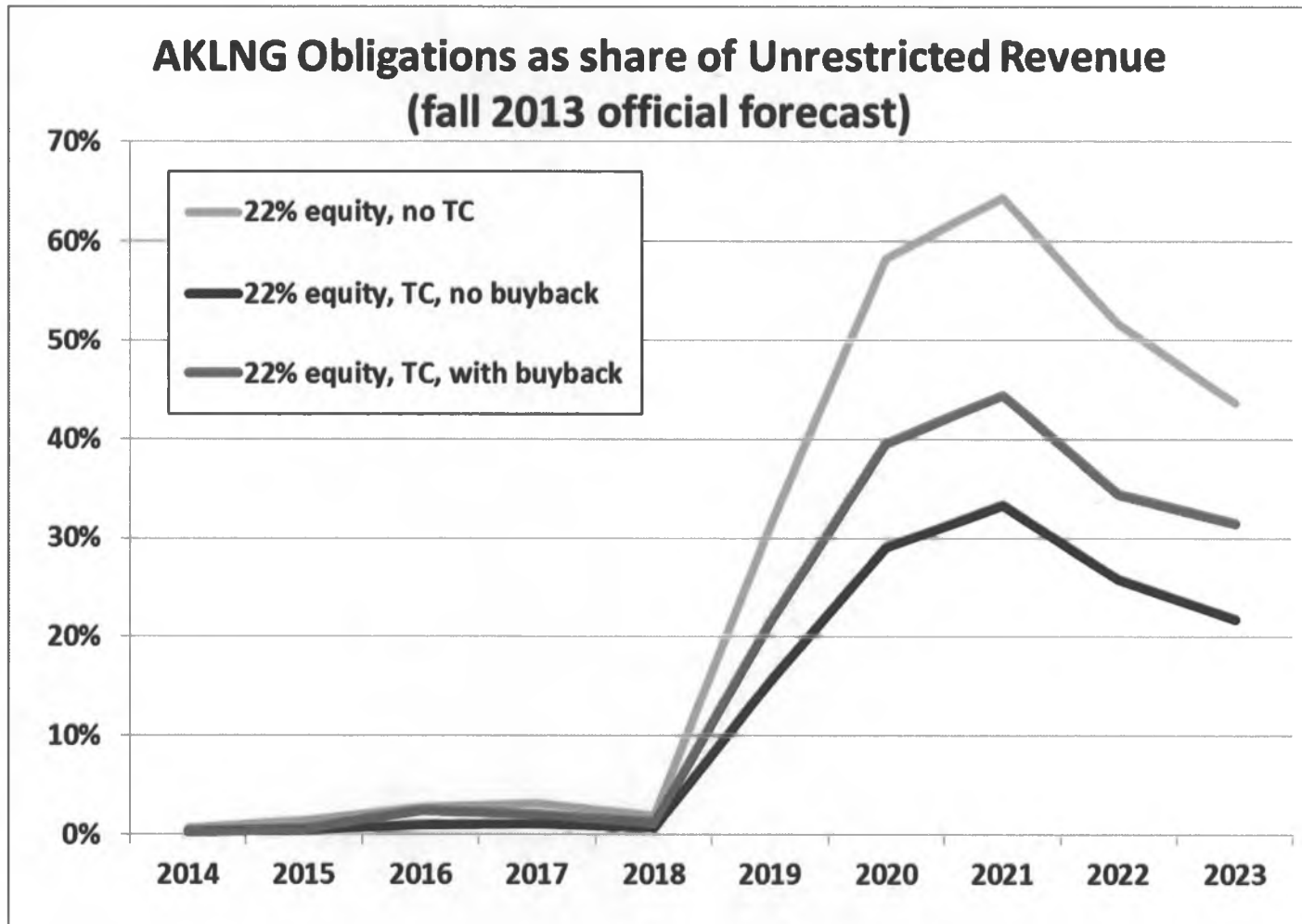
REVENUE FORECAST VS AKLNG OBLIGATIONS @ 22% STATE OWNERSHIP IN MILLIONS OF DOLLARS



Source: Department of Revenue - Revenue Sources Book Fall 2013; Black and Veatch.

Assumes obligation is due in the corresponding fiscal year; i.e. CY 2019 obligation in FY 2019, etc.

AKLNG OBLIGATIONS VS. GFUR FORECAST @ 22% STATE OWNERSHIP



Source: Department of Revenue - Revenue Sources Book Fall 2013; Black and Veatch.

Assumes obligation is due in the corresponding fiscal year; i.e. CY 2019 obligation in FY 2019, etc.

AKLNG OBLIGATIONS VS. GFUR FORECAST @ 22% STATE OWNERSHIP IN BILLIONS OF DOLLARS.

Unrestricted Revenue Forecast vs. AKLNG Obligations

| | FY 2014 | FY 2015 | FY 2016 | FY 2017 | FY 2018 | FY 2019 | FY 2020 | FY 2021 | FY 2022 | FY 2023 |
|---|---------|---------|---------|---------|---------|---------|---------|---------|---------|---------|
| GFUR - fall 2013 official forecast \$billions | \$ 4.9 | \$ 4.5 | \$ 4.6 | \$ 5.0 | \$ 5.1 | \$ 5.1 | \$ 4.8 | \$ 4.5 | \$ 4.7 | \$ 4.1 |
| GFUR - fall 2013 forecast, Mid/High case \$billions | \$ 4.9 | \$ 4.5 | \$ 4.6 | \$ 5.1 | \$ 5.3 | \$ 5.5 | \$ 5.2 | \$ 5.0 | \$ 5.3 | \$ 4.8 |

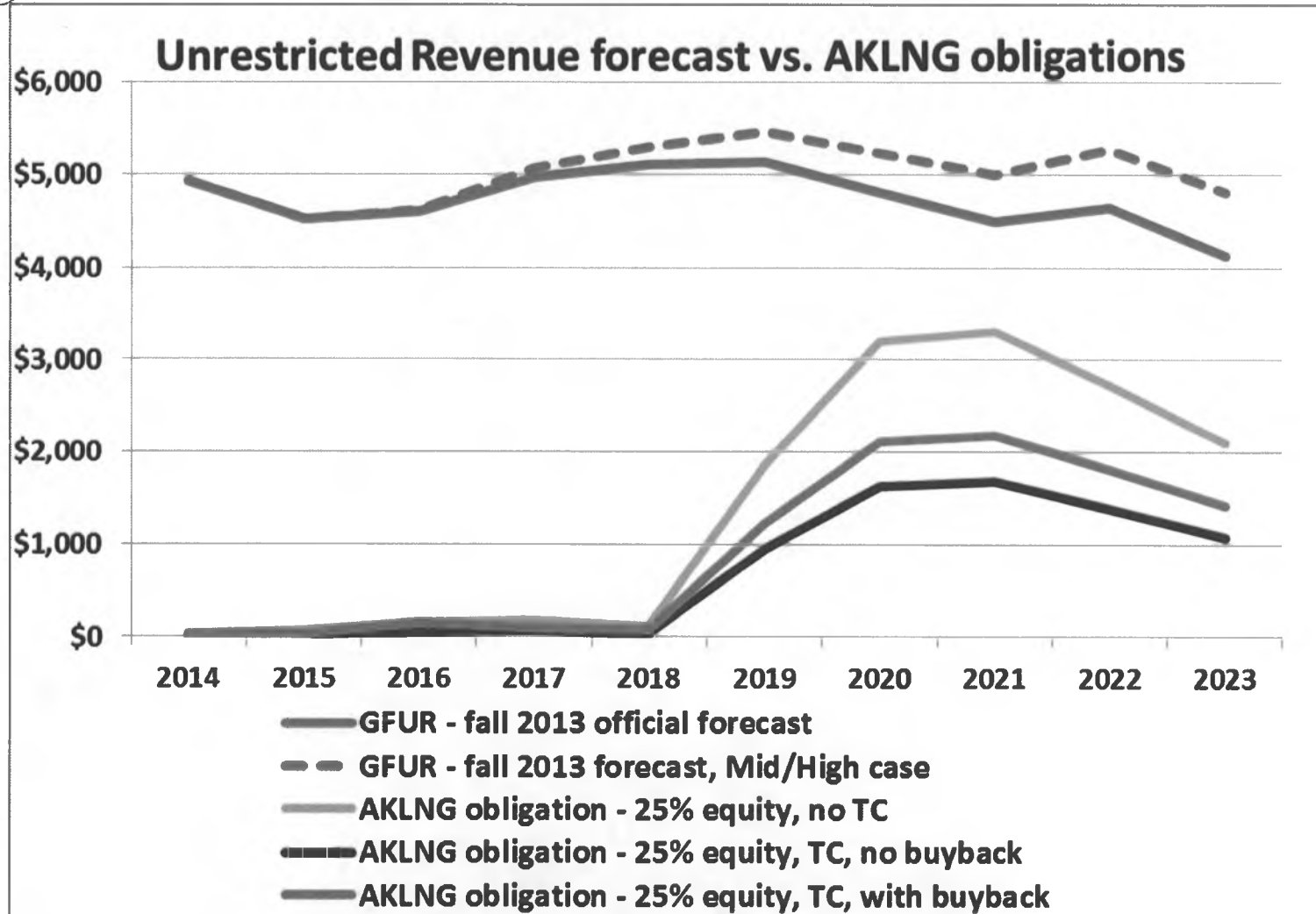
| | | | | | | | | | | |
|--|--------|--------|--------|--------|--------|--------|--------|--------|--------|--------|
| AKLNG obligation - 22% equity, no TC \$billions | \$ 0.0 | \$ 0.1 | \$ 0.1 | \$ 0.2 | \$ 0.1 | \$ 1.6 | \$ 2.8 | \$ 2.9 | \$ 2.4 | \$ 1.8 |
| AKLNG obligation - 22% equity, TC, no buyback \$billions | \$ 0.0 | \$ 0.0 | \$ 0.1 | \$ 0.1 | \$ 0.0 | \$ 0.8 | \$ 1.4 | \$ 1.5 | \$ 1.2 | \$ 0.9 |
| AKLNG obligation - 22% equity, TC, with buyback \$billions | \$ 0.0 | \$ 0.0 | \$ 0.1 | \$ 0.1 | \$ 0.1 | \$ 1.1 | \$ 1.9 | \$ 2.0 | \$ 1.6 | \$ 1.3 |

| | | | | | | | | | | |
|---|----|----|----|----|----|-----|-----|-----|-----|-----|
| Obligation % of GFUR - 22% equity, no TC | 1% | 1% | 3% | 3% | 2% | 31% | 58% | 64% | 52% | 44% |
| Obligation % of GFUR - 22% equity, TC, no buyback | 0% | 1% | 1% | 1% | 1% | 16% | 29% | 33% | 26% | 22% |
| Obligation % of GFUR - 22% equity, TC, with buyback | 0% | 1% | 2% | 2% | 1% | 21% | 40% | 44% | 34% | 31% |

Source: Department of Revenue - Revenue Sources Book Fall 2013; Black and Veatch.

Assumes obligation is due in the corresponding fiscal year; i.e. CY 2019 obligation in FY 2019, etc.

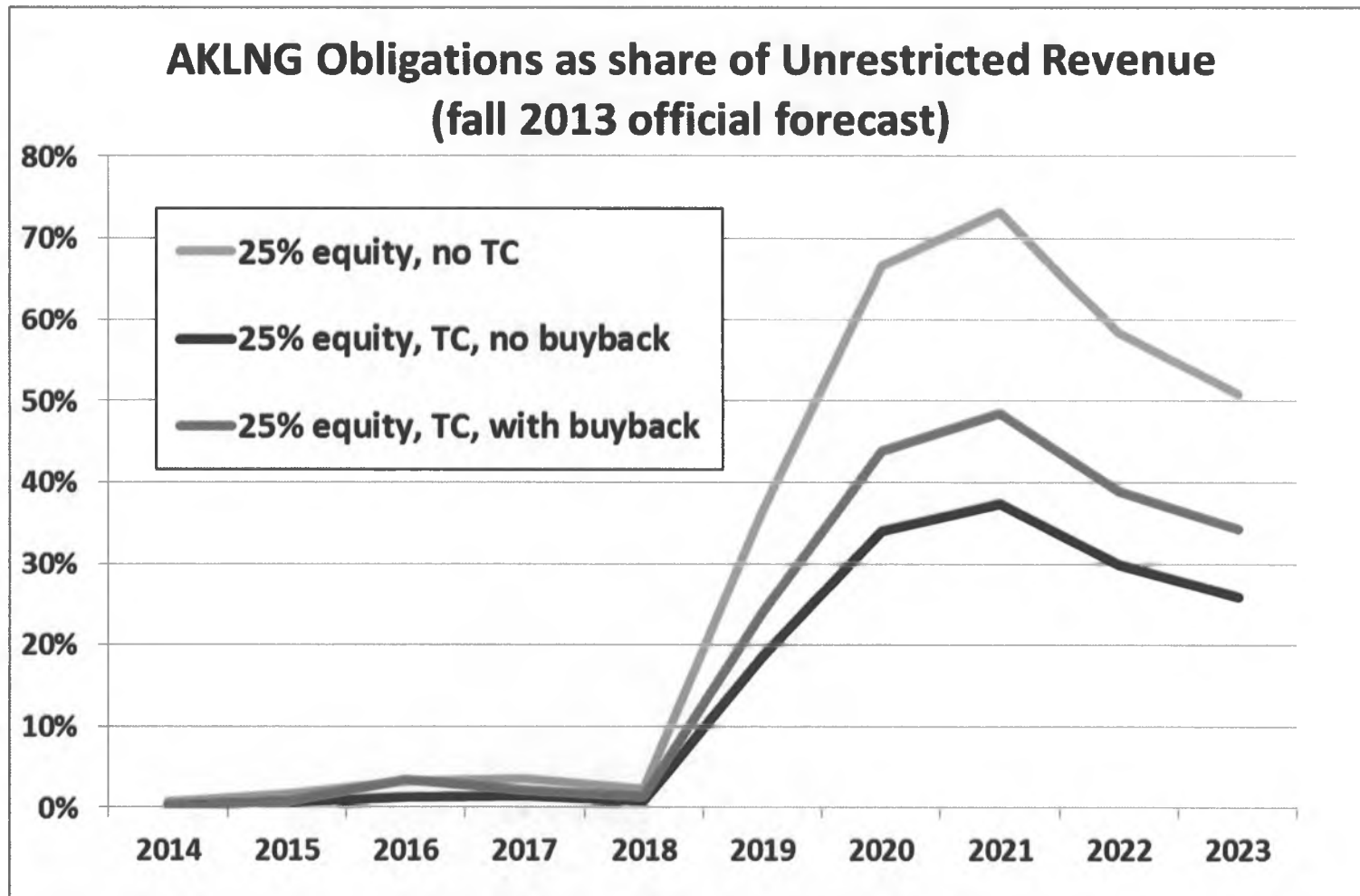
REVENUE FORECAST VS AKLNG OBLIGATIONS @ 25% STATE OWNERSHIP IN MILLIONS OF DOLLARS



Source: Department of Revenue - Revenue Sources Book Fall 2013; Black and Veatch.

Assumes obligation is due in the corresponding fiscal year; i.e. CY 2019 obligation in FY 2019, etc.

AKLNG OBLIGATIONS VS. GFUR FORECAST @ 25% STATE OWNERSHIP



Source: Department of Revenue - Revenue Sources Book Fall 2013; Black and Veatch.

Assumes obligation is due in the corresponding fiscal year; i.e. CY 2019 obligation in FY 2019, etc.

AKLNG OBLIGATIONS VS. GFUR FORECAST @ 25% STATE OWNERSHIP IN BILLIONS OF DOLLARS.

Unrestricted Revenue Forecast vs. AKLNG Obligations

| | FY 2014 | FY 2015 | FY 2016 | FY 2017 | FY 2018 | FY 2019 | FY 2020 | FY 2021 | FY 2022 | FY 2023 |
|---|---------|---------|---------|---------|---------|---------|---------|---------|---------|---------|
| GFUR - fall 2013 official forecast \$billions | \$ 4.9 | \$ 4.5 | \$ 4.6 | \$ 5.0 | \$ 5.1 | \$ 5.1 | \$ 4.8 | \$ 4.5 | \$ 4.7 | \$ 4.1 |
| GFUR - fall 2013 forecast, Mid/High case \$billions | \$ 4.9 | \$ 4.5 | \$ 4.6 | \$ 5.1 | \$ 5.3 | \$ 5.5 | \$ 5.2 | \$ 5.0 | \$ 5.3 | \$ 4.8 |

| | | | | | | | | | | |
|--|--------|--------|--------|--------|--------|--------|--------|--------|--------|--------|
| AKLNG obligation - 25% equity, no TC \$billions | \$ 0.0 | \$ 0.1 | \$ 0.2 | \$ 0.2 | \$ 0.1 | \$ 1.9 | \$ 3.2 | \$ 3.3 | \$ 2.7 | \$ 2.1 |
| AKLNG obligation - 25% equity, TC, no buyback \$billions | \$ 0.0 | \$ 0.0 | \$ 0.1 | \$ 0.1 | \$ 0.1 | \$ 1.0 | \$ 1.6 | \$ 1.7 | \$ 1.4 | \$ 1.1 |
| AKLNG obligation - 25% equity, TC, with buyback \$billions | \$ 0.0 | \$ 0.0 | \$ 0.1 | \$ 0.1 | \$ 0.1 | \$ 1.3 | \$ 2.3 | \$ 2.3 | \$ 1.9 | \$ 1.5 |

| | | | | | | | | | | |
|---|----|----|----|----|----|-----|-----|-----|-----|-----|
| Obligation % of GFUR - 25% equity, no TC | 1% | 2% | 3% | 4% | 2% | 37% | 67% | 73% | 58% | 51% |
| Obligation % of GFUR - 25% equity, TC, no buyback | 0% | 1% | 1% | 1% | 1% | 19% | 33% | 38% | 30% | 27% |
| Obligation % of GFUR - 25% equity, TC, with buyback | 0% | 1% | 3% | 2% | 1% | 25% | 48% | 51% | 41% | 36% |

Source: Department of Revenue - Revenue Sources Book Fall 2013; Black and Veatch.

Assumes obligation is due in the corresponding fiscal year; i.e. CY 2019 obligation in FY 2019, etc.

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?

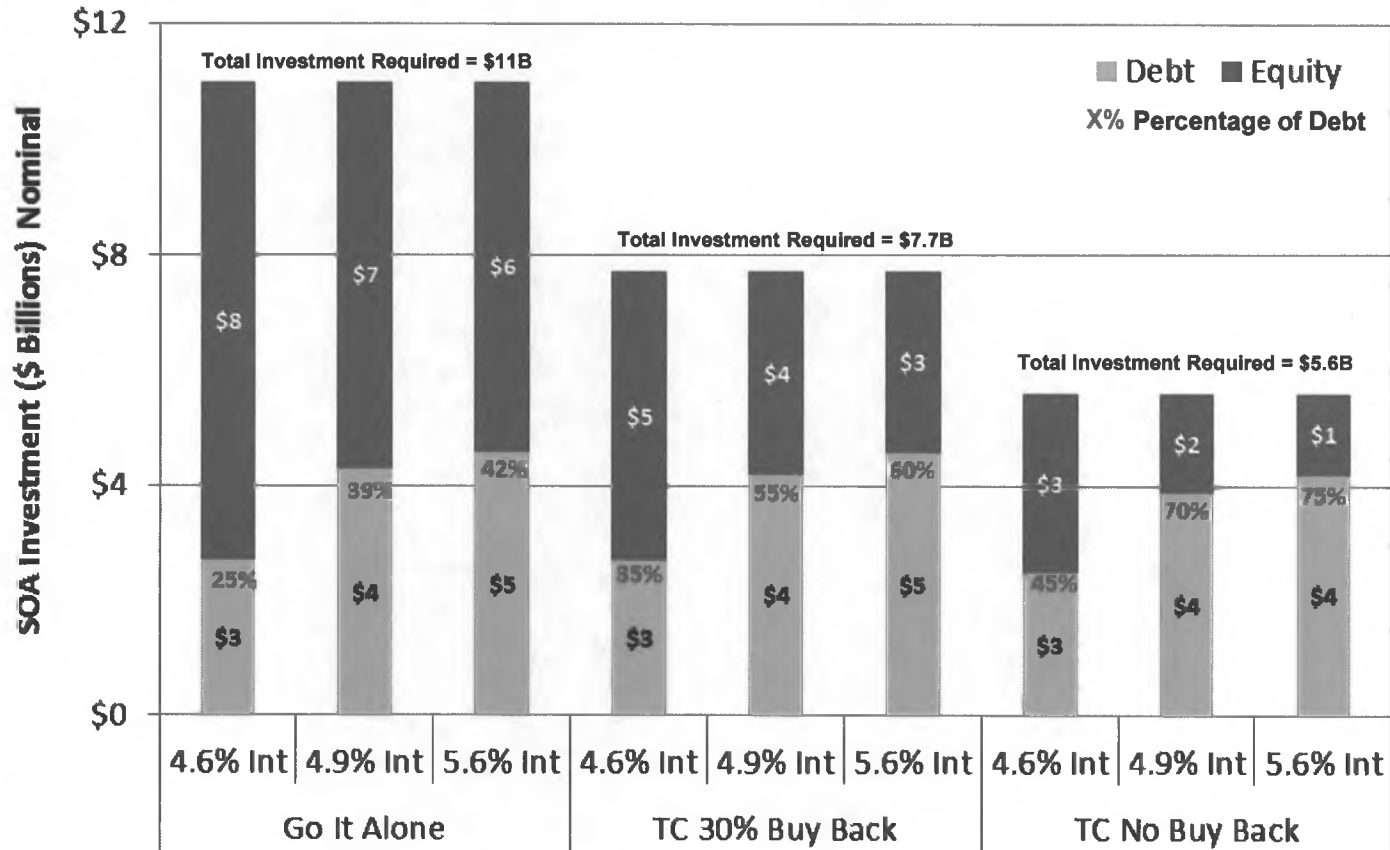
| | |
|---------------------------------|--|
| Scenario 1 (lower interest) | <ul style="list-style-type: none"> • SOA Debt at 4.6% • Debt Service limited to 3% of GFUR |
| Scenario 2 | <ul style="list-style-type: none"> • SOA Debt at 4.9% • Debt Service limited to 5% of GFUR |
| Scenario 3 (higher interest) | <ul style="list-style-type: none"> • SOA Debt at 5.6% • Debt Service limited to 6% of GFUR |

- High-level, indicative assumptions based on input from Department of Revenue
- Based on market conditions as of February 20, 2014

CAN THE STATE GO IT ALONE?

- STATE'S DEBT CAPACITY @ 20% OWNERSHIP

State of Alaska Investment in AKLNG Project – Debt Capacity for 20% Ownership

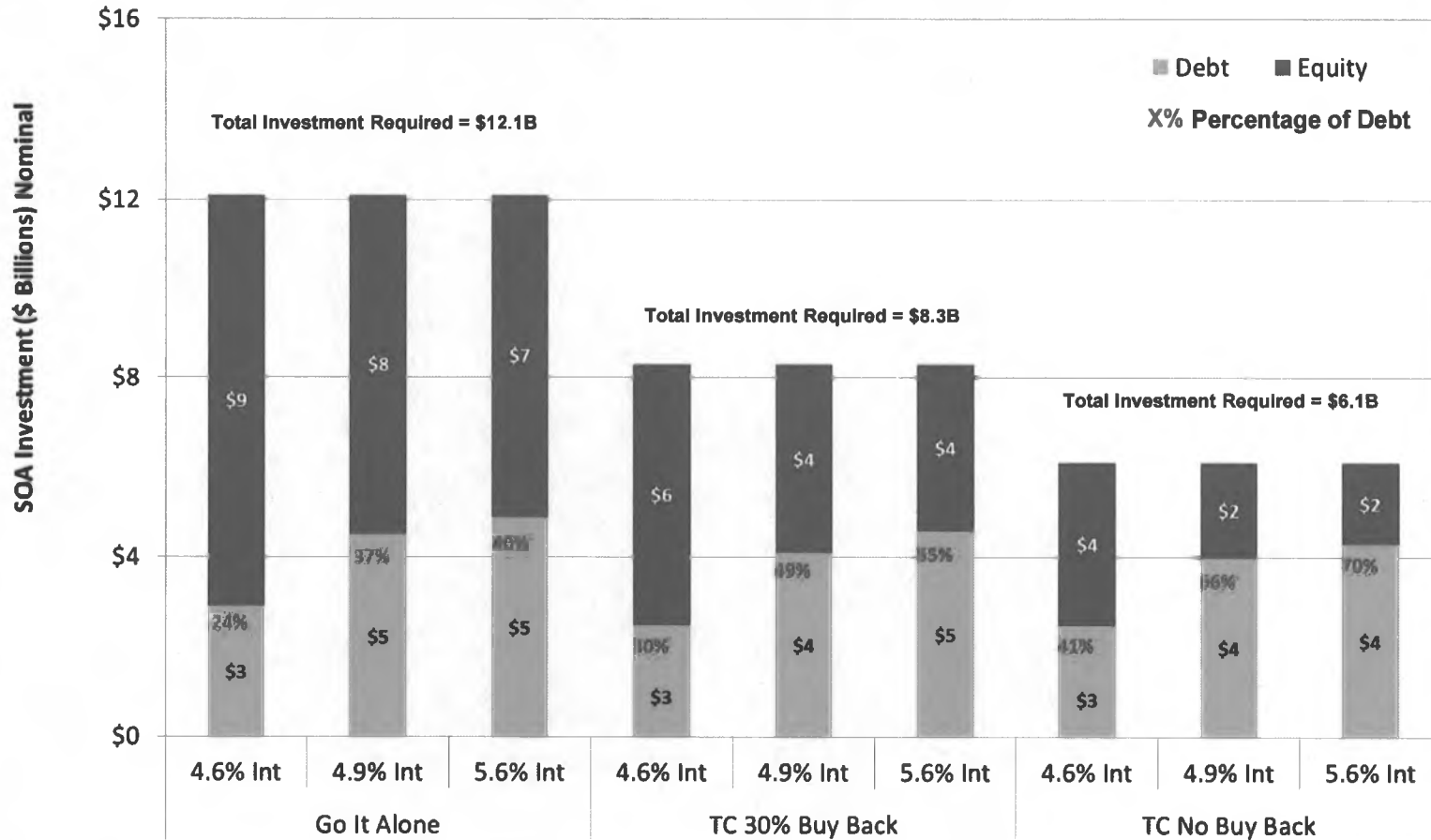


- High-level, indicative assumptions based on input from Department of Revenue
- Based on market conditions as of February 20, 2014

CAN THE STATE GO IT ALONE?

- STATE'S DEBT CAPACITY @ 22% OWNERSHIP

State of Alaska Investment in AKLNG Project – Debt Capacity for 22% Ownership



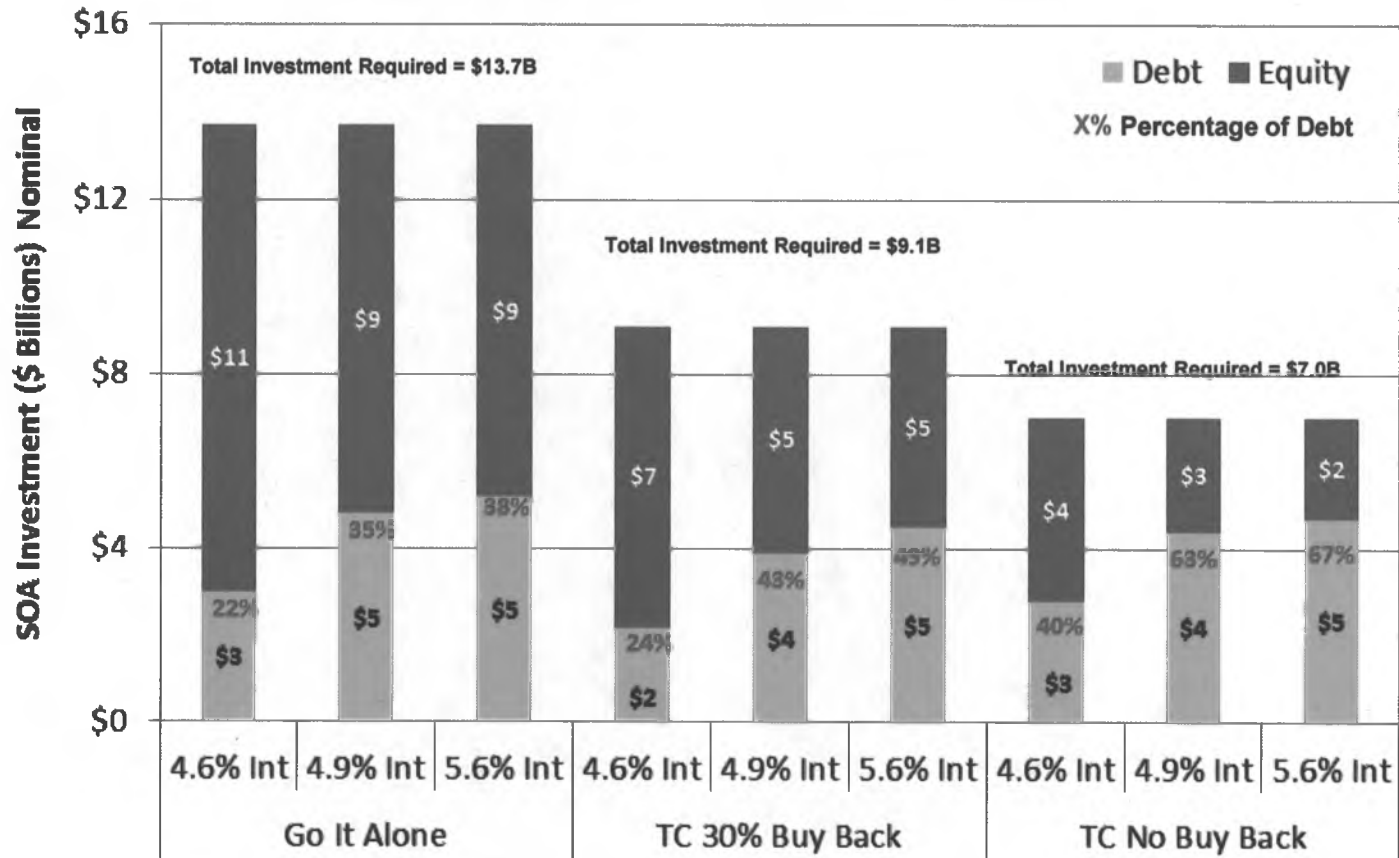
- High-level, indicative assumptions based on input from Department of Revenue
- Based on market conditions as of February 20, 2014



CAN THE STATE GO IT ALONE?

- STATE'S DEBT CAPACITY @ 25% OWNERSHIP

State of Alaska Investment in AKLNG Project – Debt Capacity for 25% Ownership



- High-level, indicative assumptions based on input from Department of Revenue
- Based on market conditions as of February 20, 2014

KENAI LEGISLATIVE INFORMATION OFFICE

Email: Kenai.Lio@akleg.gov

Phone: 907-283-2030 / Fax: 907-283-3075

WRITTEN TESTIMONY

NAME: John and Mary J Davis
REPRESENTING: _____
BILL # or SUBJECT: SB138
COMMITTEE & DATE: HRES 033114

We would like to urge our senators to pass Senate Bill 138.....

This is first of all gas that belongs to Alaskans. So, build a gas-line to Nikiski so we as Alaskan are served first. Whatever it costs it will be worth it for Alaskans to have unlimited amounts of natural gas. Please make the Alaska LNG project go to completion.

John and Mary J. Davis

48590 KSRM Court

Kenai, AK 99611

907-283-9432 HM

907-398-2630 Cell/MJ

907-283-8700 Wk Ph/ John

907-394-3159 Cell/ John

Dear House Resource Committee Members:

Among the many questions and concerns regarding the Alaska LNG Project, I am particularly concerned about what terms will be in any "project-enabling" contracts negotiated by the Administration, how much pressure there will be on the legislature to authorize one or more contracts next year, and the level of public participation in the decision-making process.

Under the Heads of Agreement, Article 4, the Alaska LNG Parties will continue Pre-FEED work through to completion "provided Enabling Legislation acceptable to the Parties is passed and other support referenced in Article 10 is maintained or progressed."

Under Article 7, in addition to providing for a confidential negotiation process, acceptable Enabling Legislation will allow for the negotiation of project-enabling contract terms that could address a wide range of topics, from state participation to upstream costs and lease expenditures to any other terms the Parties consider necessary to advance the project. Some of these contract terms are addressed as principles in the HOA, but many of the terms under Article 7 are yet to be negotiated.

Among other things, Article 10 calls for State support of use of eminent domain rights to facilitate the LNG project; appropriations, permitting and legislation for the construction of infrastructure; and unspecified support for a "healthy, long-term oil business." The list is non-inclusive so there could be more.

At least some of the State support for Article 10 items is likely to be included as terms in a project-enabling contract. Since the HOA indicates that continuation of Pre-FEED work to completion is contingent on State support, there could be enormous pressure on the legislature to ratify a proposed contract with such terms.

SB 138 is the Enabling Legislation and gives the commissioner of the Department of Natural Resources full discretion to negotiate any terms for inclusion in the proposed contracts. Though the Administration has testified they will keep the legislature informed on a confidential basis as negotiations progress, there is nothing in SB 138 to assure consultation occurs or any requirement for involving the public. That means that Alaskans will not see a proposed project-enabling contract until the contract is brought to the legislature for an up or down vote, with little opportunity to comment.

Similar to what was required under the Stranded Gas Development Act, it is reasonable to include in SB 138 a requirement for a best interest findings and determination for a proposed contract that would be subject to public review and comment and legislative consultation. Reasons to support such a requirement include:

- State participation in the LNG project and associated obligations is a significant public policy decision with long-term consequences to the fiscal future of the state. Alaskans have the right to know the basis for the Administration's decisions and the right to weigh in on these decisions.
- The public comment period will give legislators advance opportunity to consider contract terms and to hear from their constituents before a contract is formally presented to the legislature for ratification.
- There was a findings and determination with a public comment period prepared for the Stranded Gas Fiscal Contract so we know it is doable.

A draft amendment is attached for your consideration.

Changing Tides Consulting, changingtides.com
lisa@changingtides.com

CSSB 138(FIN) am
Best Interest Findings Amendment

AS 38.05 is amended by adding new sections to read:

[Sec. 1]. Preliminary findings and determination for a North Slope natural gas project contract.

(a) If the commissioner develops a proposed contract under AS 38.05.020(b)(11) – (12), the commissioner shall make preliminary findings and a determination that the proposed contract terms are in the best interest of the state.

(b) In making the preliminary findings and determination required by (a) of this section, the commissioner shall address the reasonably foreseeable effects of the proposed contract on the public revenue and public services, and shall describe the principal factors upon which the determination made under (a) of this section is based.

[Sec. 2]. Notice and comment regarding the contract.

The commissioner shall

(1) give reasonable public notice of the preliminary findings and determination made under [Sec. 1].

(2) make available to the public the proposed contract, the commissioner's preliminary findings and determination, and, to the extent the information is not required to be kept confidential under AS 38.05.020(b)(12), the supporting financial, technical, and market data, including the work papers, analyses, and recommendations of any independent contractors used by the state during development of the contract;

(3) offer to appear before the Legislative Budget and Audit Committee to provide the committee a review of the commissioner's preliminary findings and determination, the proposed contract, and the supporting financial, technical, and market data; if the Legislative Budget and Audit Committee accepts the commissioner's offer, the committee shall give notice of the committee's meeting to the public and all members of the legislature; if the financial, technical, and market data that is to be provided must be kept confidential under AS 38.05.020(b)(12), the commissioner may not release the confidential information during a public portion of a committee meeting; and

(4) establish a period of at least 30 days for the public and members of the legislature to comment on the proposed contract and the preliminary findings and determination made under [Sec. 1].

[Sec. 3]. Coordination of public and legislative review.

To the extent practicable, the commissioner shall coordinate the public comment opportunity provided under [Sec. 3](4) with a review by the Legislative Budget and Audit Committee under [Sec. 3](3).

[Sec. 4]. Final findings, determination, and proposed amendments; execution of the contract.

(a) Within 30 days after the close of the public comment period under [Sec. 3](4), the commissioner of natural resources shall

(1) prepare a summary of the public comments received in response to the proposed contract and the preliminary findings and determination;

(2) after consultation with the commissioner of revenue, prepare a list of proposed amendments, if any, to the proposed contract that the commissioner of natural resources determines are necessary to respond to public comments;

(3) make final findings and a determination as to whether the proposed contract, including any proposed amendments prepared under (2) of this subsection, is in the best interest of the state.

(b) After considering the material described in (a) of this section and securing the agreement of the other parties to the proposed contract regarding any proposed amendments prepared under (a) of this section, if the commissioner determines that the contract is in the best interest of the state, the commissioner shall submit the contract to the governor.

(c) The commissioner's final findings and determination under (a) of this section are final agency decisions.

[Sec. 5]. Legislative authorization.

The governor may transmit a contract developed under AS 38.05.020(b)(11) – (12) to the legislature together with a request for authorization to execute the contract. A contract developed under AS 38.05.020(b)(11) – (12) is not binding upon or enforceable against the state or other parties to the contract unless the governor is authorized to execute the contract by law. The state and the other parties to the contract may execute the contract within 60 days after the effective date of the law authorizing the contract.

From: Lynn Willis
10140 Hillcrest Lane
Eagle River, Alaska 99557

March 28, 2014

To: Alaska Legislature
House Resources Committee

Testimony regarding SB 138

I am a residential consumer of Natural Gas representing myself. I am extremely leery of this Legislation and I believe, based on our track record regarding gas supply, I have good reason to be so. I urge you to thoroughly vet this legislation before passage.

I have listened to the testimony regarding SB138. I am impressed with the analysis and your questions. Thank you for inviting testimony that was not invited by the Senate.

I am sure you have hired the best and the brightest consultants to evaluate this proposition; however, didn't you do that with AGIA? Now six years later after creation of AGIA with over 300 million dollars gone from the state treasury and with at least 130 million more owed to Trans Canada we have neither an inch of pipe purchased nor any application from any producer to AOGCC for release of a single molecule of gas.

My concern is about domestic supply of energy for Alaskans including natural gas. The Alaska State Government has yet to create a comprehensive energy plan that would identify the primary source of renewable and non-renewable energy for each region of the state for electrical generation, space heating, vehicle mobility, local industrial production and energy resources for export. This failure to have a comprehensive plan results in what we see currently as we purchase study after study and/or expend state revenue in a seemingly endless pursuit of the next best idea.

We have spent how much on the "Cook Inlet Renaissance" for supply contracts through 2018? We have spent how much on the AGDC/ASAP project which now seems about to be abandoned for this AKLNG project. AGIA is still restricting volume limits for the AGDC/ASAP project. We won't even consolidate our natural gas demands in the rail belt region as we pursue trucking LNG into Fairbanks. Aren't we now competing with the Cook Inlet gas producers and haven't we created the almost unbelievable situation where, to various degrees, we are expending state funds to pay for three pipe line efforts at the same time (AGIA, AGDC/ASAP, and AKLNG).

Testimony (L.Willis) re: SB138 March 28, 2014.

If the House emulates the Senate, this Legislation will become law. Soon we will be in pre-election pre-feed and once again hopes of Alaskans will rise.

I ask you to not restrict yourselves to a specific time limit to vet this legislation. If for no other reason you should be extremely cautious in your deliberations because we are now in deficit spending. I would like to remind you that we live in a sovereign not an investment bank.

As you proceed toward passage of SB 138 please reflect on testimony from Professor Emeritus Scott Goldsmith who has long been associated with the University of Alaska Institute of Social and Economic Research (ISER). Professor Goldsmith was testifying as a private citizen on March 25th (at 73:10) before Senate Finance. At that hearing, Professor Goldsmith stated that we are now drawing down our cash reserves at a rate of about 7 million dollars per day.

At that rate of spending we will soon enough not be able to afford business as usual in State Government including passing legislation that might cost us millions of dollars just for testing the viability of the AKLNG project as currently envisioned. We need to learn as much as we can, including exploring our options, before passage of SB 138. Thank you. Lynn Willis

TransCanada Capital Project Performance



| Project | Capital Cost* (\$ Billions) | In-Service Date | Cost Performance | Schedule Performance |
|-----------------------------|--------------------------------|-----------------|---------------------|-------------------------|
| Bécancour | 0.5 | Q3 2006 | 6% under | 15 days late |
| Tamazunchale | 0.2 | Q4 2006 | 8% under | 30 days early |
| Cartier Wind (Phases I-III) | 0.6 | Q4 2006/07/08 | 3% under | 14 days early |
| Michigan Storage Expansion | 0.1 | Q4 2007/08 | 10% under | On time |
| Portland Energy Centre | 0.7 | Q1 2009 | 2% under | 21 days early |
| Kibby Wind (Phases I & II) | 0.4 | Q4 2009/10 | On budget | On time |
| Alberta Pipe | 0.2 | 2009/10 | 29% under | On time |
| North Central Corridor | 0.8 | Q2 2010 | 15% under | On time |
| Halton Hills | 0.7 | Q3 2010 | On budget | On time |
| Groundbirch | 0.2 | Q4 2010 | 44% under | 30 days late |
| Keystone (Phases I & II) | 6.0 | Q3 2010/Q1 2011 | 12% over | On time |
| Bison | 0.6 | Q1 2011 | 11% over | 60 days late |
| Coolidge | 0.5 | Q2 2011 | 12% under | On time |
| Guadalajara | 0.4 | Q2 2011 | On budget | On time |

* *TransCanada share in Canadian dollars. Excludes interest during construction. Estimated Keystone (Phases I & II) costs.*