Summary Report on the Review of the Alaska LNG Project Process

Office of the Governor
State of Alaska

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The following report summarizes the results of a review of the process established for the proposed liquefied natural gas ("LNG") project currently being worked on by the State of Alaska, TransCanada, ExxonMobil, BP, and ConocoPhillips under the negotiating framework most recently enacted in 2014 by Senate Bill 138: the Alaska Liquefied Natural Gas Project ("AKLNG Project," "AKLNG," or "Project"). The majority of challenges are structural and commercial in nature rather than technical. The report will first discuss the history of prior Alaska gas pipeline development efforts, and then the commercial difficulties faced by the AKLNG Project.

I. HISTORY OF EFFORTS TO COMMERCIALIZE NORTH SLOPE GAS

The current configuration of the AKLNG Project is the latest in numerous efforts to export North Slope natural gas dating back to the 1970s. This section of the report discusses those efforts in context of the current AKLNG Project and what can be learned from those prior unsuccessful attempts.

A. Early Projects

Prior to the mid-1980s, there were efforts to advance several different Alaska gas pipeline projects, including those by Prudhoe Bay leaseholders BP, Atlantic Richfield and ExxonMobil (together with successor companies, the "Producers"), and separately by El Paso and Foothills (a predecessor to TransCanada). These attempts reflected, among other issues, the two competing themes consistently present in North Slope gas commercialization efforts.

First was the ongoing debate about whether a project should be a North American project through Canada or an LNG project to tidewater in South Central Alaska. For instance, in 1977, the Carter Administration determined a project should go through Canada, and Congress enacted the Alaska Natural Gas Transportation Act to enable the same. Competing national priorities – based largely on ever-fluctuating Lower 48 gas prices and estimated gas supply – saw seesawing support of a Canadian and LNG project. The Reagan and George H.W. Bush Administrations supported the Yukon Pacific Corporation ("YPC") LNG export effort (discussed below), including a presidential finding in 1988 that North Slope gas could be exported to Asia as well as cooperation in that almost decade long permitting effort. In 2004, the Alaska Natural Gas Pipeline Act was enacted, which was aimed at *inter alia* supporting rapid permitting of a

Canadian project. However the Act also provided support for an LNG project by extending federal loan guarantees to a project that exported gas to the Lower 48.

High natural gas prices and advances in drilling technology led to the "shale gas revolution" and a major market shift in the 2007 to 2010 timeframe, which saw increases in Lower 48 natural gas reserves and production, and decreases in current and projected North American gas prices. This once again confirms that the primary markets for Alaska gas are global (primarily Asian) and not domestic, and thus support an LNG as opposed to a Canadian project.

The second reoccurring theme running through various project development efforts remains whether the project should be developed by the Producer companies or by an independent corporate or governmental effort. Multiple starts and stops have reflected this contentious three-decade plus dynamic.

B. Yukon Pacific Corporation

In 1983, former governors Wally Hickel and Bill Egan, following the suggestion by Governor Hammond, formed YPC, which was a proposed LNG project to export to Japan, South Korea, Taiwan and possibly the U.S. West Coast, but not exclusively the West Coast as El Paso's earlier proposed project had planned. In 1986, a deep pocket became part owner with YPC: Texas Gas Transmission Inc., a subsidiary of Lower 48 railroad and shipping giant CSX Corp. Through the 1990s, YPC expended approximately $100 million to engineer and permit a LNG project from the North Slope to Valdez, to run parallel to the Trans Alaska Oil Pipeline ("TAPS"). This effort advanced further than any North Slope gas commercialization effort before or since, including, with the issuance of a Final Environmental Impact Statement by the Federal Energy Regulatory Commission in 1995, securing the senior federal and state permits necessary to construct a project. This was the most aggressive effort of a non-Producer project sponsor to follow the "permit it and they will come" strategy. But like other independent efforts, YPC was unable to secure access to the gas resource from the Producers or support from the State administration. Different justifications have been offered regarding why the Producers would not commit gas, including the economic environment, the need to continue re-injecting gas at Prudhoe Bay to maximize oil production, and a view that the Producers simply refused to deal with an independent company. Without gas to ship, YPC began slowly winding up its efforts and all permits and rights-of-way lapsed by 2011.

C. Stranded Gas Development Act

Since at least the late-1990s timeframe the Producers have followed a strategy that is still being followed today. This approach requires the State of Alaska to provide "fiscal certainty" before the Producers will build or allow to be built a North Slope natural gas pipeline. Although the scope of fiscal certainty has varied over the years, it has retained the constant hallmark of requiring the State of Alaska to adopt royalty and tax terms on oil and gas acceptable to the Producers, and for those terms to be locked in and unchangeable by the State for a prolonged period.

In 1998, the Alaska legislature adopted the Stranded Gas Development Act ("SGDA") as a specific legislative framework for the State to negotiate a proposed gas pipeline deal including fiscal certainty. Although SGDA negotiations theoretically allowed proposals by independent pipeline companies, and several large companies like TransCanada, Mid-America, and Sempra Energy did attempt to participate, during this era the State focused almost exclusively on a deal with the Producers for a project through Canada. Under this iteration the Producers held off on substantial permitting and engineering work until a fiscal deal with the State was finalized and approved by the legislature. Thus the State was in the position of not seeing work on a gas pipeline project advance until each Producer was satisfied with fiscal terms. Like the current S.B. 138 process, the State had little to no leverage and found itself negotiating to the least common denominator on each issue, and on the project schedule, with three different companies. As the party that most desired the project, and desired it on the most rapid timeline, the State made drastic concessions to achieve an agreement. The SGDA process resulted in significant turnover and resignation in the Department of Natural Resources ("DNR"), including an estimate the SGDA contract would have cost Alaska $13.5 billion including concessions on oil

While a contract with the Producers was negotiated and finalized by the State's executive branch in the spring of 2006, the terms of the contract were not perceived as acceptable to Alaskans. The unacceptability of the contract, in conjunction with the political corruption accompanying the companion deal negotiated by the State with the Producers on the overhaul of state production taxes on oil, meant the contract was neither seriously considered nor approved by the legislature. It was abandoned when Governor Palin took office.

D. Alaska Gasline Inducement Act

In response to the perceived failings of SGDA, the Palin administration pushed for and the legislature passed in 2007 the Alaska Gasline Inducement Act ("AGIA"). This process solicited bids from companies interested in state financial subsidies to permit and potentially build a pipeline. In 2008, TransCanada's bid to obtain the required permits along the route to Canada (with a secondary option to permit to Valdez for LNG export) was selected. Pursuant to the terms of AGIA, the State subsidized 50% of TransCanada's qualified expenditures incurred before the end of the first binding open season in June 2010, and 90% of TransCanada's qualified expenditures thereafter.

Frustrated by the stranglehold the Producers had during the prior SGDA process, and the State's lack of leverage in the same, the State attempted with AGIA to independently advance a project with a YPC-like "permit it and they will come" concept. For a number of reasons the effort failed. Within days of the award of the contract to TransCanada, TransCanada let it be known they expected Producer participation, and ExxonMobil was later brought in as a project partner. Thus the "independent" pipeline project was now controlled by a Producer company. Over the next few years, after the 2010 open season failed, it became clear the gas markets had changed several years prior and a project through Canada was no longer viable. However, rather than TransCanada and ExxonMobil pursuing an LNG project as allowed under the AGIA bid, the AGIA process morphed into an SGDA-like process for an LNG project controlled by the Producers. This is notwithstanding the strong expression of interest from Asian buyers in purchasing LNG from an AGIA project in response to the 2012 AGIA solicitation of interest.

Neither company responded to any of the Asian market's written expression of interest in LNG from the AGIA process.

E. Denali Pipeline

At the same time that AGIA was launching, BP and ConocoPhillips began a pipeline project to Canada along the same approximate route as AGIA. Whereas ExxonMobil chose to join the AGIA process, BP and ConocoPhillips opted to develop their own project as an alternative to having to participate in the AGIA effort. This project was ultimately abandoned due to impacts caused by the development of shale gas on the North American gas market, and BP and ConocoPhillips joined ExxonMobil and TransCanada in the post-AGIA LNG project effort.

F. Alaska Sponsored Projects

In addition to the SGDA, AGIA and now S.B. 138 processes directed by the executive branch, there have been three other significant governmental project efforts.

1. Alaska Gasline Port Authority ("AGPA"): AGPA was formed in 1999 by the North Slope Borough, Fairbanks North Star Borough and the City of Valdez to progress an LNG project. The original purpose of AGPA was to obtain an IRS ruling stating that an AGPA owned project would be exempt from federal taxation. AGPA did receive such a ruling from the IRS, but the Producers declined that tax-exempt structure. After that AGPA project efforts largely included partnering with energy companies (Mitsubishi Corporation, Sempra LNG, Bechtel Corporation, Williams Pipeline) to either build an independent project or, after issuance of the AGIA license, attract buyers interested in the AGIA option to Valdez. Although AGPA had initial success in bringing on project partners, similar to YPC, its inability to engage with the State executive branch or the North Slope producers resulted in those efforts failing.
2. Alaska Natural Gas Development Authority ("ANGDA"): In 2002, Alaska voters formed ANGDA by ballot initiative to build an LNG project at tidewater. ANGDA was almost immediately marginalized due to lack of support for that project scope by various state administrations. Residing within the executive branch, it was tasked with various non-core assignments such as the Y-line from Delta to South Central for a Canadian project, working on a pipeline from Anchorage to Fairbanks, and looking at various other in-state energy projects. Never particularly popular with the executive branch or legislature, it was ultimately terminated by the legislature in 2013 through House Bill 4.

3. Alaska Gasline Development Corporation ("AGDC"): After the award of the AGIA license, the legislature began to support a state-sponsored effort for a smaller bullet line project from the North Slope to tidewater. Initially at the direction of the legislature through House Bill 369 (2010) this effort was worked by the Alaska Housing Finance Corporation. In 2013, AGDC was created and funded with approximately $355 million to advance the Alaska Stand Alone

Pipeline Project ("ASAP") at state expense. ASAP focused on a small project less than 500 million cubic feet per day. AGDC followed the "permit it and they will come" approach, including completing substantial engineering and permitting work. ASAP currently has a class 3 engineering estimate and the pipeline right-of-way permits on state land. Although ASAP has progressed engineering and permitting on gas conditioning and pipeline facilities to Big Lake, it has not substantially engaged Producer or third party project participation, including securing gas supply or commitments for gas purchase if supply were available, identifying or working on a liquefaction site, or securing contribution by project partners of external capital. Additionally, in 2014, S.B. 138 tasked AGDC with holding the State's interest in the AKLNG liquefaction plant, and in the gas conditioning plant and pipeline if TransCanada does not fulfill that role for the State. AGDC currently participates in AKLNG by owning 25% of the LNG facilities. The workflow and funding for the ASAP and AKLNG efforts within AGDC is also separated.

G. The AKLNG Project

On March 20, 2012, the chief executives of ExxonMobil, ConocoPhillips and BP informed then-Governor Parnell that their companies had started working with TransCanada to assess whether a project to export LNG from Alaska to Asia made more sense than a pipeline to serve North America. With a Canadian project no longer economic, the effort focused on a project to tidewater in south central Alaska. After settlement of the Point Thomson litigation between the State and Producers in 2012, the completion of a concept selection effort that led to adoption of a liquefaction site at Nikiski in 2013, and passage of favorable oil and gas production tax legislation in the form of S.B. 21 in 2013, the parties entered into a Heads of Agreement ("HOA") in January of 2014 to jointly advance the AKLNG Project.

The effort resulted in passage of S.B. 138 in 2014, and termination of AGIA shortly thereafter. Under the HOA, S.B. 138, and the subsequently executed preliminary front-end engineering and design ("Pre-FEED") Joint Venture Agreement, the State is again focused almost exclusively on a Producer project (the ASAP effort is largely on hold). Like the failed SGDA process before it, the AKLNG process requires the State to negotiate project terms and schedules that are acceptable to every Producer.

One distinction between the SGDA and the AKLNG Project, in addition to the latter being an LNG project, is that negotiation of the fiscal deal is being progressed concurrently with initial technical work. Thus, although Pre-FEED work is occurring, each party reserves and expects to exercise its right to not do additional technical work – including entering into FEED – unless the fiscal and commercial contracts are satisfactory and the Project otherwise meets internal corporate priorities to move forward.

II. COMMERCIAL CHALLENGES SPECIFIC TO THE AKLNG FRAMEWORK

The remainder of this report analyzes the major commercial challenges presented by the AKLNG framework from the State's perspective.

A. There is no alignment on when the AKLNG Project should begin FEED or construction, and time delays kill many projects.

The AKLNG Project and S.B. 138 were based on an assumption that all three Producers were as motivated as the State was to bring an LNG project to fruition as soon as reasonably possible. There was a basic failure to realize that each Producer has their own individual economic and strategic concerns that will dictate their view of when the AKLNG Project should proceed. Until there is alignment into a single view, individual participants within the AKLNG process are not incentivized to agree to finish the commercial agreements necessary to advance AKLNG. The divergence of views appears exacerbated by the prolonged depression of oil prices and its impact on the ability of each company to make capital expenditures of the magnitude required by the Project.[1] Part of the lack of alignment derives from some Producers having other LNG projects that are competing with AKLNG, both in terms of markets and access to corporate capital. An unfortunate consequence of this process is the AKLNG Project will only proceed on a pace set by the schedule of the Producer who is most reluctant to proceed.

This results in all parties negotiating to the least common denominator (again). Because all AKLNG parties must agree on every issue of every commercial agreement, the party that most wants a project is pressured to make the most concessions to advance the Project. As the party with the strongest interest in an Alaska project progressing, the State is the party with the strongest incentive to make concessions to progress the Project. At the end of the day, however, external events relating to one or more Producers may dictate that no project goes forward under the SB 138 process no matter what concessions are made.

To mitigate the issues presented by the requirement that all AKLNG participants align in order to progress the Project, the State must attempt to achieve the following:

1. The State must have the ability to prevent any AKLNG partner from causing unreasonable delay to the Project schedule, or to proceed without an AKLNG partner who unreasonably delays; and

2. If one or more Producers withdraw at any point from the Project, the State must have the ability to acquire that party's interest in the Project and get a reasonable commitment from the withdrawing party (or parties) to toll gas through the gas pipeline and liquefaction facilities, or sell its gas to the State so that the State can proceed with moving forward without delay.

The State is currently in the process of negotiating a withdrawal agreement and milestones to deal with these points. However, it is unclear if the State will be able to successfully negotiate a

[1] Goldman Sachs states oil could go as low as $20. *See* Exhibit 1

reasonable agreement that will ensure the State will have the gas commitment and engineering data to proceed without having to duplicate the work already performed on AKLNG.

B. A 42" pipeline is unlikely to incentivize future exploration and development by third parties.

Early on in the AKLNG Project, it was recognized that there was a fundamental difference between the State of Alaska's primary design criteria and the Producers' preferences on sizing the AKLNG pipeline. Each Producer was focused on the lowest cost transportation capacity needed to monetize their own Prudhoe Bay Unit ("PBU") and Point Thompson Unit ("PTU") resources. Under this design basis, the 42 inch diameter pipe is the best option, even though it does not easily accommodate entrance of new gas into the Project until after PBU and PTU come off plateau and begin to decline. The State of Alaska is more broadly focused on encouraging opening up the North Slope's gas resources to development and exploration beyond PBU and PTU, as anchor fields for AKLNG, and the capability to serve greater in-state needs. Without question, the best way to put more oil into TAPS is to have a gasline that allows new companies who explore for oil to ship their newly found gas to market while exploring for oil. The 48 inch pipe is a much better option to meet these requirements. The State's modeling indicates that the additional cost to build the 48 inch pipe will be repaid due to the lower operating costs resulting from the larger volume, more efficient pipeline after the first 14 years of operating. Nonetheless there is resistance to allow easy access and low cost expansion to third parties.

The pipeline sizing debate is a key decision that the State considers as a Project priority, because it is the State that has the highest interest in encouraging exploration and making sure other gas, if discovered, has access to the system. When attempting to determine the optimum pipeline diameter, there are many factors that influence the final selection. The importance of each factor varies with the perspective of the decision-makers. Some of the main factors are described below:

1. Capital Costs: For the base case throughput, the 42 inch pipe is the lowest cost option. The 48 inch pipe, transporting an equal amount of gas, will cost more. But the incremental cost of purchasing and installing the larger, heavier pipe is largely offset by the fact that the 48 inch pipeline only requires 4 or 5 compression stations in comparison to 8 for the 42 inch.
2. Operating Costs: Again, at the base case throughput, the 42 inch has a lower cost of service than the 48 inch largely because of the lower initial capital cost. But because the 48 inch pipeline burns less fuel (there are fewer compression stations), and needs less maintenance, the larger pipe over time begins to overtake the smaller, less efficient pipe. If one assumes a cost for fuel of $4 per thousand cubic feet ("mcf"), then the additional investment in the 48 inch pipe will be recouped after 14 years of production.
3. Expansion: The 42 inch pipeline can be expanded by up to 1 billion cubic feet per day ("bcf/d"). The 48 inch pipeline can be expanded by up to 2.3 bcf/d. The incremental cost of expanding the 42 inch pipeline is double what it costs for the same 1 bcf/d additional capacity with the 48 inch pipeline.

Furthermore, since expansion requires 10 additional compression stations on the 42 inch pipeline compared to 4 on the 48 inch pipeline, operating costs for an expansion are far less for the larger, more efficient pipe, which will be almost 15% less expensive to operate if fuel gas is assumed to be $4/mcf.

4. Delay: A change in pipe size from 42 inch to 48 inch at this point could add 6-8 months to the pre-FEED deliverables but should not cause a significant delay of a final investment decision ("FID").

A significant amount of analysis regarding the risks and benefits associated with the 42 inch and 48 inch pipe sizes has been done and will be provided in a supplemental report to the legislature.

C. The ownership interests in PBU and PTU are significantly different among the three Producers, and the two fields are at very different stages of development.

The current ownership interests in PBU and PTU are depicted below:

	PBU	PTU
EM	36%	62%
CP	36%	5%
BP	26%	32%

PBU is a mature field with a great deal of knowledge about the gas resource and length of plateau. PTU is a less mature field with much less knowledge of its gas resources and length of plateau. ExxonMobil with 62% of PTU and BP to a lesser extent with 32% of PTU have tremendous economic incentive to be able to overlift their gas from PBU to provide security for LNG sales contracts on PTU gas that may stretch the bounds of current knowledge of PTU resources. ConocoPhillips has approximately 40 times as much gas at PBU as it has at PTU. Consequently, ConocoPhillips has no interest in taking any risk with respect to potential effects from overlifting at PBU to support PTU. ConocoPhillips is incented to either minimize or eliminate any potential for long term risks associated with having PBU support problems or a shorter plateau at PTU, or to be currently compensated for any support it will provide.

The problems associated with disparate ownership in the two fields among Producers can be alleviated by a gas balancing agreement with specific constraints on (or cash compensation for) the use of PBU gas to support PTU. Unfortunately, because the State is not an upstream owner, there is little the State can do as a negotiating party in this situation except encourage the parties to act in a reasonable manner to resolve the current impasse. It may be that this issue will not get resolved until there is alignment by all parties to proceed as soon as reasonably possible.

D. There is uncertainty regarding the role of TransCanada.

Currently, TransCanada owns 25% of the gas treatment plant ("GTP") and 25% of the pipeline portion of AKLNG. AGDC currently owns 25% of the LNG facilities; if the State terminates the TransCanada relationship, AGDC will own 25% of the entire Project. A decision on TransCanada's role in the equity of the AKLNG Project has not yet been made, but the State has prepared an analysis of the risks and benefits associated with buying out TransCanada's ownership in the midstream.[2] Having a third-party be responsible for part of the Project development costs and the equity commitment is advantageous in that it reduces the pre-operation capital requirements for the State. However, the State's analysis indicates that TransCanada's participation in the Project is very expensive and reduces alignment between the State and the Producers. The analysis indicates that the State's revenue from the Project could be increased by an average of about $400 million per year during the first 20 years of operation if AGDC takes on TransCanada's portion of the pipeline and GTP. Additionally, if TransCanada is in the Project, the State cannot act as a full partner with the Producers, and the State's information and control over the entire Project is reduced.

The termination of TransCanada must occur prior to the end of 2015. DNR will owe TransCanada shortly after it issues a Notice of Termination a payment equal to roughly $80 million depending on the date of termination. Funding that would have been available for such an acquisition of TransCanada's interest was removed from AGDC's budget last session. Therefore, to proceed, an appropriation request of the legislature will need to be made this fall. In addition, an appropriation request by AGDC will be needed to cover future expenditures related to the 25% interest in the GTP and pipeline that TransCanada would be transferring to AGDC. If the State exercises its option to terminate TransCanada's participation in the Project, failure by DNR or AGDC to obtain appropriations to reimburse TransCanada and fund AGDC's participation in the midstream portion of the Project will substantially impair the ability of all AKLNG parties to move the process forward. It is therefore essential that members of the legislature review the attached study and understand the benefits associated with the buyout of TransCanada, as well as any associated risks.

E. The Commissioner of DNR cannot make the RIK/RIV determination without fully-termed project-enabling agreements.

The Commissioner of DNR is required to make a statutory finding that taking either royalty gas in kind or in value is in the best interest of the state when deciding how to dispose of the State's gas. The DNR Commissioner must analyze the difference in benefits to Alaska between taking royalty in kind ("RIK") and taking royalty in value ("RIV"). Pursuant to S.B. 138, the Commissioner is authorized to make lease amendments locking in either RIK or RIV during the Initial Project Term (expected to be 25 years) to provide certainty on the gas volumes that the State and the Producers will each have available for long-term gas sales contracts. Under typical lease terms, DNR can switch back and forth from RIK to RIV, and vice versa, on 90 days' notice. Pursuant to Section 8 of the HOA entered in to by all AKLNG parties, the

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[2] DNR retained Black & Veatch ("BV") to do a study of the pros and cons of terminating TransCanada's status in the Project.

Commissioner's royalty election – giving up the State's right to switch between taking RIK and RIV, and deciding on one or the other for a period up to 25 years – is subject to the execution of project-enabling agreements that include "satisfactory arrangements for disposition of the State's share of LNG." The DNR Commissioner therefore cannot make a RIK election until the parties have agreed to project-enabling contracts that include satisfactory arrangements for disposition of the State's LNG. Although Commissioner Myers has begun the royalty election determination process, the Producers' unwillingness to finalize any of the project-enabling agreements has prevented Commissioner Myers from completing that analysis.

Without fully-termed commercial agreements that establish how the State will receive and dispose of its royalty gas share, Commissioner Myers cannot confirm that taking royalty in kind is in fact in the state's best interest, nor can he determine that taking royalty in value would instead be in the best interest of the state, as contemplated by AS 38.05.182. This problem therefore requires that the parties reach alignment on fully-termed project-enabling agreements.

F. The parties are not aligned on whether the State should pay Field Cost Allowances.

The 1980 Prudhoe Bay Unit Royalty Settlement Agreement requires the State to pay field costs for gas royalty produced from DL-1 leases associated with a major gas project (like AKLNG), whether the State takes the gas RIK or RIV. The State's position is that no field costs should be paid to the Producers, even for PBU gas covered under the 1980 PBU Royalty Settlement Agreement, because the Producers can deduct such field costs as leasehold expenditures against their oil production tax, and also because the State is investing in 25 percent of the AKLNG Project. There is not alignment on this issue.

G. The Producers are unwilling to move forward without more fiscal certainty than the State is willing to provide.

The Producers have made clear that fiscal certainty is a threshold issue that is required to move forward on any North Slope natural gas project. The State has entertained requests from the Producers that it provide certainty on AKLNG property taxes and gas production taxes for 25 years, and that it agree to not impose a gas reserves tax during the construction period. However, certain Producers have indicated an expectation for greater fiscal certainty on unrelated taxes and it has not been confirmed that all Producers will proceed without fiscal certainty on oil.

The State has consistently messaged to Producers that the State is unwilling to provide fiscal certainty on oil for this Project. It is the Administration's belief that the people of Alaska will not support a constitutional amendment that authorizes fiscal certainty on oil and unrelated taxes, and the economics of the Project do not require it. The State is concerned that offers made during past gas project negotiations, such as the SGDA, established Producer expectations that are unrealistic.

H. The parties disagree on the form of dispute resolution.

The State has consistently messaged to Producers that the State will follow its standard administrative and procedural processes and resolve disputes in Alaska under the State of Alaska's sovereign systems and under Alaska law. The State is unwilling to change the way disputes are resolved in Alaska, and agreements to which the State is a party should provide for the standard process for dispute resolution. It is also unacceptable to the State to surrender application of Alaska law to the Project as a general proposition. Although there has been little dialogue on this issue so far, the State has made it clear that it will not progress agreements to final form without resolution on dispute resolution mechanics and agreement that Alaska law will govern this Project. Unless each Producer agrees to respect the Alaska's laws and administrative and judicial processes, the parties will be unable to reach agreement on commercial contracts. Simply put, the State will no more agree to cut the judicial branch of government out of this process than it would agree to remove the legislative or executive branches.

I. The Project as currently structured will make project financing more difficult.

The current AKLNG ownership model being put forward by the Producers is both untested and raises a number of complexities that would need to be addressed, particularly given the scale of the AKLNG financing requirement. The structure differs from the more integrated "buy/sell" or tolling based common financings that have been customary models for LNG liquefaction projects. Because each member (or its affiliate) will separately market its LNG entitlement under an "equity lifting" mode (although there is scope for the State to market jointly with one or more of the Producers or their affiliates), the LLC will not have any independent revenue stream; the LLC will not buy or sell LNG, nor will a toll be paid by the members for use of the midstream or downstream assets. Thus, the LLC itself will not have any capacity to raise financing under a common project financing of the sort that has been the feature of most, if not all, precedent LNG project financings. The State believes that the current Project structure must be revisited in order for the Project to be successful.

In conclusion, the project process adopted by S.B. 138 poses serious challenges that make AKLNG very difficult to progress in a manner, and on a timeline, that can maximize benefits to Alaskans. A fundamental issue is the underlying assumption that governed the drafting of S.B. 138: that all parties would be equally motivated to get a project done in a reasonable time. This assumption has been proved by history, and within the current process, to be invalid.

Additionally, a significant challenge to the State in advancing a project process under S.B. 138 is that the framework gives little to no negotiating leverage to the State.

Cohesion between the Administration and the legislature regarding how the State can gain better leverage to pressure development of a project is essential. As the "owner" of this resource, we must work together to successfully identify a meaningful resolution to the current difficulties.