ALASKA STATE LEGISLATURE

SENATOR
Gene Therriault
119 N. Cushman Suite 101
Fairbanks, Alaska 99701
(907) 488-0857
FAX (907) 488-4271

While in Juneau
State Capitol
Juneau, Alaska
99801-1182
(907) 465-4797
FAX (907) 465-3884

Senate
Senate District F

July 24, 2006

The Honorable William Corbus
Commissioner, Alaska Department of Revenue
PO Box 110430
Juneau, Alaska 99811-0430

RE: Alaska Stranded Gas Fiscal Contract between the State of Alaska and BP Exploration (Alaska) Inc., ConocoPhillips Alaska, Inc., and ExxonMobil Alaska Production Inc. ("Fiscal Contract") / Preliminary Findings and Determination ("Preliminary Findings")

Dear Commissioner Corbus:

Attached, please find my formal comments on the proposed Stranded Gas Development Act fiscal contract (the Contract) between the State of Alaska (the State) and BP Exploration (Alaska) Inc., ConocoPhillips Alaska, Inc., and ExxonMobil Alaska Production Inc. (Collectively, the Producers).

They have been structured for ease of reading and reference in the following way. Section I is the introduction and summary of these comments. Section II describes why the Contract is not ripe for consideration or execution. Section III discusses the terms of the Contract. Section IV discusses the Preliminary Findings and Determinations of the Commissioner of Revenue. Section V makes recommendations for changes to the Contract.

I have compiled these comments based on the reports and presentations made by consultants retained by the Joint Legislative Budget and Audit Committee, which I chair. Those individuals are: Don Shepler and Philip Gildan of the law firm Greenberg Traurig, LLP; Barry Pulliam, Dr. Anthony Finizza, Dr. Jeffrey Leitzinger, Rick Harper and the rest of their team at Econ One Research, Inc.; Daniel Johnston; James Eason; and James Barnes of the law firm Barnes & Cascio.

While I have relied on these comments and reports to provide background and material, the conclusions and recommendations are my own.

Thank you for this opportunity to comment.

Sincerely,

Gene Therriault
Senator

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I. Introduction and Summary

The Contract prepared by the parties is based largely on AS 43.82, The Alaska Stranded Gas Development Act (SGDA). At the time the SGDA was enacted, the market dynamics were significantly different than they are today. The goals of the SGDA are to cause Alaska's stranded gas to be developed without altering the tax and royalties on existing infrastructure and production, and to maximize the benefit to the State's citizens. For a variety of reasons, the Contract is not yet ripe for consideration or execution. The overall structure of the Contract fails to address critical issues and represents an unbalanced set of commitments and obligations among the parties. The Preliminary Findings and Determinations suffer from serious factual errors, incorrect treatment of shipping commitments, and misplaced fears regarding the threat posed by LNG.

The Contract is not ripe for consideration at this juncture. The Contract, as drafted, leaves too many material terms critical to the State's interests unknown. It is, frankly, premature to execute the Contract with all of its binding commitments on the State. The State's consideration to the Producers has been provided, but the Producers' *quid pro quo* consideration to the State lacks certainty and substance.

To enable the achievement of the goals of the SGDA, the Act empowers the State to make certain concessions to qualified persons. The Contract is supposed to legally document the promises of the Qualified Plan submitted by the Producers and the goals of the SGDA. Inasmuch as the State, through the Contract, is addressing the Producers' fiscal certainty requirements, prudence dictates that the Producers, through the Contract, provide the State assurances that the State will realize the goals of the SGDA resulting in an operational gas pipeline. The Contract represents an unbalanced set of commitments and obligations on the part of the State without any firm commitment to construct and finance a pipeline.

The SGDA requires the Commissioner of the Department of Revenue to reach three preliminary findings at this stage of the process: (1) that the gas is stranded; (2) that the Contract is in the long-term fiscal interest of the State; and (3) that the Contract furthers the purpose of the SGDA. After review of the presentations by the Administration's consultants, the Legislature's consultants, the Producer's representatives, and general public comment I have reached the conclusion that the factual data does not support the Finding.

The overarching problem with the contract is that it is not an agreement to develop the stranded gas resources of Alaska. Rather, it is an agreement to study development, with no commitments to construct a pipeline or commit to ship gas on the pipeline. It has no time limits or performance standards for completion of a pipeline, while effectively precluding the State from seeking alternative means to construct a pipeline if progress is not being made.

II. The Contract is Not Ripe for Consideration or Execution

The Contract is not ripe for consideration at this juncture. A contract requires the parties' agreement on all material terms, or the contract is null and nothing more than an unenforceable agreement to agree. The Contract, as drafted, leaves too many material terms critical to the State's interests unknown. It is, frankly, premature to execute the Contract with all of its binding commitments on the State, when the Contract includes no agreement on the following material terms:

(1) Terms and Conditions for the Creation, Funding, Operation and Management of the Mainline Entity Tasked With Implementing the Qualified Project Plan and the other Mid-stream and Up-stream Entities (Alaska LLC Agreement(s))
(2) Terms and Conditions of and Parties to the Alaska to Alberta Project Entity (Canada Entity Agreement)
(3) Terms and Conditions for the Coordination of Project Entities and Project Implementation In-State, in Canada and in the Lower-48 (Coordination Agreements)
(4) Parent Company Guarantees of Affiliates' Obligations and Performance of Delegated Responsibilities
(5) Plan for obtaining Canadian regulatory approvals for the Alaska to Alberta Project and coordination of such approvals with approvals for the Mainline Project
(6) Commitment by the Producers to Subscribe For Sufficient Shipping Capacity in the Pipeline to Obtain Project Sanction
(7) Marketing Entity for State Gas
(8) In-state pricing policy for deliveries of State Gas
(9) AOGCC-approved off-take rates for Prudhoe Bay and Pt. Thomson

A contract requires mutual consideration from all parties. The Contract lacks such mutual consideration at this time. The State's consideration to the Producers has been provided through fiscal terms and certainty on those terms. However, the Producers' *quid pro quo* consideration to the State lacks certainty and substance as there is no firm commitment to construct and finance a pipeline or to operate and expand the pipeline to promote exploration and discovery of new petroleum resources.

The Contract relies upon the future negotiation and agreement on other essential implementation agreements which have not been presented and which define the parties' obligations and rights regarding the operation, enforceability, and commitments of the parties under the Contract. The entities and documents set out below are contemplated by the Contract. However, they do not yet exist and the terms and conditions of their governance are not known:

- the instruments creating the Alaska Project Entities and the various State entities;
- the governance agreements controlling the relationships among the interest holders and the management of each Alaska Project Entity;
- the operating agreements of each Alaska Project Entity;

- the agreement with a Canadian entity creating the Alaska to Alberta Entity and the governance agreements of such Alaska to Alberta Entity
- the agreements coordinating the operations between and among the Alaska Project Entities and the Alaska to Alberta Entity;
- the ship-or-pay arrangements and marketing arrangements for the State's gas;
- the investment obligations and financing arrangements for the Project Entities and the State entities;
- the undertakings by the State and the Producers' parent companies concerning:
    - the financial and performance guarantees for their respective subsidiaries; and
    - the coordination of the US and Canada regulatory processes.

The reason why the unknowns listed above are relevant to the State's participation is because they are needed to understand whether, on a macro level, the Applicants' Qualified Project Plan can be implemented and will meet the requirements of the Alaska Stranded Gas Development Act. They are also needed to understand, on a micro level, how the Qualified Project Plan will be implemented, including understanding the governance of the Project Entities, the management and control of the Project, and the State's rights and obligations with respect to the Project.

The apparent difficulty the Producers and the Administration are having in finalizing a draft of the first of these entity agreements for the Mainline Entity, and their inability to complete such negotiations in time for submittal as part of the proposed Contract, underscores the material importance of the terms and conditions of the Project Entity agreements and the lack of ripeness in considering the Contract without the Project Entity Agreements in place.

This is troubling since the specific terms of the Project Entity LLC agreements can limit the rights and actions of the State with respect to critical decisions affecting the project. For example, it would be expected that the Mainline Entity LLC agreement will specify the voting rights of the participants with respect to finalizing a design and specifications for the pipeline, approving the filing of the application for a FERC certificate, designing the pipeline tariff, sanctioning an Open Season, accepting or rejecting a certificate, structuring the financing of the pipeline and deciding whether to proceed with construction of the project or terminate. Decisions with respect to how and when to expand and extend the pipeline, a critical State requirement for the Project, will also be addressed in the Entity Agreements, as will decisions with respect to whether the pricing of initial and expansion capacity will be done on an incremental or rolled-in basis.

Since the Contract makes up for lost tax revenue with sales of its in-kind gas share, the State interest is best served by low shipping rates. The State, with its unique interest in maximizing the exploration and production by new gas explorers, and in its role as a shipper has a great interest in assuring that the pipeline's rates are as low as possible and that expansion opportunities are timely provided and economically feasible for new gas explorers. Companies that compete with the Producers in the exploration and production of gas are more completely aligned with the State since they would be competitively disadvantaged by higher-than-necessary tariff rates. Thus, the State has a unique interest vis-à-vis the Producers in assuring through terms of the Contract that a lowest reasonable cost strategy be used to set tariff rates for the system.

In the absence of some governing instrument establishing that decisions of a Project Entity will be made by a super-majority or some regulation protecting the rights of minority interest holders, the State's ability to influence a decision of a Project Entity through its minority interest will be very limited. Also, it should be noted that the State's interest in a Project Entity would be held indirectly through a State owned company, such as AK Pipeco. The economic drivers for the board of AK Pipeco will be commercial in nature and, as such, expecting AK Pipeco to be the primary defender and an effective advocate of the State's sovereign interests seems unlikely.

Since Parties are not required to enter into a commercial arrangement under Article 5, failure to finalize these entity agreements constitutes an exception to "Diligence" under that same article. Practically speaking, Project Planning activities cannot begin until there is a Project Entity to conduct such activities.

The State's minority status combined with the suppression of the State's regulatory regime (discussed in Section III) will restrict the ability of the State to achieve its purposes as sovereign, except to the extent the achievement of those purposes is explicit in the Project governance documents.

The Contract's provisions in Article 8 that commit to a National Energy Board (NEB) regulatory process in Canada as well as the provisions in Article 7 specifying joint State-Producer ownership in Canada are likely to lead to significant delays in advancing the project. As the Fiscal Interest Finding acknowledges[1], TransCanada holds specific rights and assets relevant to the Alaska to Alberta Element of the Project. However, those rights are pursuant to the Northern Pipeline Act (NPA) rather than the NEB.

TransCanada's ownership of permits and easements represents an opportunity to accelerate the process of permitting and certificating the entire Project if TransCanada's role in the Project is negotiated as part of the Contract process. However, their expressions of dissatisfaction with the Contract's provisions are likely to lead to disputes in the Canadian regulatory process—disputes that are specifically cited as an exception to "Diligence" in Article 5.

The Alaska Oil and Gas Conservation Commission (AOGCC) has a very important role in this project—to protect the public's interest by preventing waste and insuring greater ultimate recovery of both oil and gas. To fulfill this role, the AOGCC will decide what gas production rates should be allowed from Prudhoe Bay, Pt. Thomson, and other North Slope oil and gas fields. Considering only the laws of science, these decisions are very simple: to prevent waste and maximize hydrocarbon recovery, produce all of the oil in a reservoir first and then "blow down" its gas cap only when there is no commercially recoverable oil left.

[1] See FIF-ES-17, FIF-186, FIF-200, FIF-234, and FIF-236

Looking simply at the reservoir engineering science, producing gas from an oil reservoir while there is still commercial oil remaining to be produced will cause a portion of the oil resources to be lost, and, thus, it is always best to keep the gas in an oil reservoir until no more commercially recoverable oil remains. Only then should the gas cap be "blown down."

This is especially true at Pt. Thomson. Considering only the conservation of Alaska's hydrocarbon resources, Pt. Thomson should be developed as an oil field. It is the largest proven—but undeveloped—field in Alaska. It is also what's termed a retrograde condensate reservoir. According to a white paper by the AOGCC, to maximize production and recovery from a condensate reservoir, it is necessary to keep the reservoir pressure high until the condensate has been recovered. This method delays gas sales, but it results in greater ultimate recovery of both liquid and gaseous hydrocarbons.

However, for the North Slope there will be a trade-off between leaving black oil in the ground and leaving gas stranded, and this trade-off will be influenced by several factors. The remaining useful life and increasing operating cost of the aging North Slope infrastructure will impact the balance between losing oil and stranding gas. The minimum rate at which TAPS can operate will impact the economic life of the gas production because, as long as TAPS is operating, many of the operating, repair and replacement costs will be shared by both the oil and gas production, thus extending the time before either becomes uneconomical.

The AOGCC must balance black oil recovery optimization with gas recovery optimization to insure maximum total hydrocarbon recovery, and this will be no trivial task. Until the point in time when the Producers will commit the necessary volumes of gas to the pipeline to support the Project (without harming the State's interest in hydrocarbon recovery), it is premature for the State to make binding commitments and concessions with regard to all of the leases identified in Exhibit D of the Contract.

Two items directly related to the decision to take the State's royalties and taxes in gas should be included in the Contract prior to it becoming effective. The creation of the State's gas marketing entity is necessary to ensure the State is able to successfully market its gas pursuant to the Contract. The State will be competing with the Producers as well as many other world-class organizations in both the natural gas commodity markets and in the pipeline capacity markets by taking delivery as specified in the Contract. The public—and its representatives in government—need to know that the decision to take gas in-kind will deliver the promise of an enduring economic future rather than saddle the State with a tangle of complicated burdens without significant fiscal benefits.

Mistakes made during the late-1970s and early-1980s related to the State's royalty oil programs proved costly and embarrassing. Fortunately, not all of the State's royalties and taxes were at stake. If Alaskans wish to avoid making similar mistakes with North Slope natural gas—with all of the State's marbles at stake—the sooner a State marketing entity is created and staffed with experienced professionals, the better.

Development of the State's in-state pricing policy for deliveries of volumes at the four off-take points made available through Article 9 is also critical. For many communities north of the Alaska Range, the promise of a gas pipeline has included access to cheaper, cleaner, more efficient energy. However, without an obligation on the part of the State's Producer partners to sell gas in-state, the burden of providing supplies for in-state demand is likely to fall to the State. For residents able to gain access to the gas, maximizing benefits to the end-users—at the expense of the State treasury—will be important. For residents off of the pipeline system, there is likely to be a higher demand for maximizing the benefits to the treasury. This is likely to be a very divisive issue among Alaskans and within the Legislature.

Each of these issues is critical to understanding and weighing the benefits and risks embodied in the Contract, and to providing the State with commensurate consideration for the fiscal certainty terms provided to the Producers. Resolution of these items could mitigate concerns with the Contract terms identified in Section III and the accompanying recommendations contained in Section V.

III. Contract Terms

The goals of the Stranded Gas Development Act (SGDA) are to cause Alaska's stranded gas to be developed without altering the tax and royalties on existing infrastructure and production, and to maximize the benefit to the State's citizens. To enable the achievement of these goals, the SGDA empowers the State to make certain concessions to qualified persons. The Producers submitted a Qualified Plan to the State promising to meet the stated goals of the SGDA in exchange for the State providing the Producers fiscal certainty. The Contract is supposed to legally document the promises of the Qualified Plan and the goals of the SGDA. Inasmuch as the State, through the Contract, is addressing the Producers' fiscal certainty requirements by making material and long-term tax and royalty concessions to the Producers and those concessions will become effective when the Contract is executed, prudence dictates that the Producers, through the Contract, provide the State assurances that the State will realize the goals of the SGDA resulting in an operational gas pipeline. To that end, this section addresses the structure and specific terms of the Contract that do not reach the promise of the Qualified Plan and intent of the SGDA.

Contract Structure

The overall structure of the Contract fails to address critical issues and represents an unbalanced set of commitments and obligations among the parties. All of the parties have acknowledged in committee discussions and testimony that the State's fiscal certainty concessions and commitments become binding upon execution. However, there is no clear, binding commitment by the Producers to implement the Qualified Plan terms and build the pipeline. At a minimum, the State's commitments and concessions on fiscal certainty must be made contingent upon the construction of the pipeline. The purpose of the Contract is to deliver a constructed pipeline, not to economically backstop the Producers. The Producers currently have the obligation to develop the State's gas resources under existing leases with the State[2]. Fiscal certainty concessions provide the incentive for constructing the pipeline, but without pipeline construction, there should be no concessions.

There are no parent company warranties and the parent and subsidiaries are in no way restricted from taking financial, legal, policy, or other actions that are in conflict with the express and implied terms of the Contract between the State and these specified subsidiaries. Producers have unilateral rights to add parties and to delegate rights and obligations by notice without any limitations or approvals [Art. 31.1(b)]. Without parent company economic and performance guarantees, the State has no certainty that the pipeline will be constructed.

The Contract does not financially bind BP, Conoco Phillips, or ExxonMobil. Only the stipulated subsidiaries stand behind performance. There are no warranties or representations in the Contract as to the capital structures or minimum capitalization of these subsidiaries, as to their sale or encumbrance of assets or transfer or issuance of shares and control, or as to maintenance of financial health, credit ratings, debt/equity ratios, tax compliance or compliance with laws. No evidence of any due diligence on the financial underpinnings or where-with-all of these entities exists.

The Contract seems to use the defined terms "Participants" and "State" in a generic sense despite the fact that the Contract contemplates numerous Project entities, Participant entities and State entities will be formed and will have the rights and obligations. (i.e. in Article 5 Work Commitment is a Producer duty but elsewhere the Mainline entity is responsible for doing the pre-Sanction work.) The Contract identifies Project Elements in Article 4, and Articles 5, 6, 7, and 9 contemplate the creation of separate legal entities to develop, own and operate each of the Project Elements, and to implement the general terms of the Contract. However, the Contract provides no guidance or direction as to the structure, governance and operation of such Entities, the coordination between and among the Entities and the parties to the Contract, or the interface of the terms and obligations set forth in the Contract with the as-yet-unknown terms and conditions in the Project Entity agreements.

The Project Entities are charged with undertaking the Project planning under the QPP, to update and amend the QPP, to structure and process the FERC and NEB project application and certification review, to determine whether to proceed with construction, to determine whether to terminate the Project or proceed to operation, to determine financing plans for the Project and capital contribution obligations, to structure the Pipeline tariff, to decide whether to expand or extend the Pipeline, and to own and operate the designated segments of the pipeline system both in and outside the state.

[2] See the legal opinion prepared by the law firm Hosie, McArthur, LLP and dated June 1, 2005.

In essence, the Contract delegates the establishment of all of the material terms of implementing the Project, the essential consideration to the State, to future negotiations among the parties outside of the Contract. The importance of the Project Entity agreements to the implementation of the intent of the Legislature set forth in the SGDA to ensure the construction of the Project can hardly be overstated. Without these essential terms negotiated within the Contract, the Contract provides no consideration to the State for the State's fiscal certainty to the Producers. The Contract is a one-sided nullity. Just listing the depth and breadth of the decisions and responsibilities delegated to the Project Entities under the Contract demonstrates the point:

- The Mainline LLC formation and governance agreement will reportedly be a template for all of the other LLC formation and governance agreements. However, deviations from the Mainline template will need to be made for purpose, parties, percentages, and duties of each other LLC. However, the Mainline LLC formation and governance agreements are not agreed to and not available. The Canadian Project entities will be a JV and no formation or governance agreements are available. The operators for the various Project entities are not agreed to or known and the operating agreements managing and controlling the operator's activities are not yet known.

- The Mainline LLC will reportedly be set up as a Delaware LLC to enable full flexibility of contract. In light of the non-alignment of the State's interest and the Producers interest in many aspects of pipeline management and operations, it may be preferable to use an Alaska LLC, or to include in the Delaware LLC governance documents, requirements that the members, and particularly the operator, act for the best interests of the LLC[3].

- The affiliates of the counterparties which will become the members of the LLCs may not yet be formed (i.e. AK Pipeco has not been authorized). They are likely to be single purpose entities which are not creditworthy and no provision has been made to establish or otherwise guarantee their credit.

- The State's gas marketing affiliate ("AK Gasco"), which will hold the ship-or-pay commitment for the State's in kind gas has not been formed and the corresponding formation and governance agreements and AK Gasco's firm transportation agreement have not yet been prepared.

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[3] The specific terms of the Project Entity agreements can limit the rights and actions of the State with respect to critical decisions affecting the Project. The state law in which an LLC is set up can establish or negate certain duties among the parties that serve to protect minority members. The Alaska LLC Act imposes a much greater duty of care and fair dealing upon owners of an LLC than does the Delaware LLC law—which the Administration has indicated is intended to be the state in which the Mainline Entity LLC will be established. Such a duty of care and fair dealing is important where the State is a minority interest owner of the LLC. Without such duties being imposed by law the managing members of the LLC or the majority owners would be free to pursue their own self interests, and pursue activities contrary to the interest of the LLC and the Project. The choice that the Administration seems to have made with respect to the state in which to establish the LLC is not optimal from the State's standpoint as a minority interest owner—at least not without some duty of care to the Project, the LLC, or the members that exceeds that established in the Delaware LLC law.

The Administration's position was premised on the concern that the State may need to take self-interested positions contrary to the interests of the LLC. The Administration did not want to face a claim of breach of duty for taking such actions. However, the flip side of this concern highlights the risk that a Producer (or some combination of them) would take a position in its (or their collective) self-interest that may be inconsistent with the interests of the LLC and purpose of the SGDA Contract. The question comes down to whether the State believes it or one of the other members of the LLC has a greater temptation to act in its self-interest and contrary to the interests of the LLC.

- Producers have unilateral rights to add parties and to delegate rights and obligations by notice without any limitations or approvals (Article 31.1(b)), unlike Assignment (Article 31.1(a)) which requires DNR approval. The full implications of these rights to delegate are not yet known and will likely have many unintended consequences.

- The Administration indicated in testimony that the Fiscal Contract and LLC agreements will need to be "synchronized" to reconcile rights and obligations and to "connect the silos". This is expected to be in a coordination agreement that is not available and may not have been drafted.

- No parent company guarantees (performance or payment) are required by the Contract despite the lack of creditworthiness. However, because the State is the named entity in the Contract and does not have the benefit of Article 31.1 the State will likely be a guarantor for all State entities.

- The regulatory application process will require coordination at levels above the members of the Project entities but as yet there is no provision for coordination among parent companies.

Contract Term

The contract contemplates effectiveness for at least 35 years after the commencement of commercial operations with certain allowances to extend this period to 45 years. The SGDA states that the term of the Contract shall be for no longer than is necessary to develop the stranded gas, with a maximum not to exceed 35 years. The SGDA maximum does not eliminate the need to justify the primary limitation of demonstrating what term is necessary to develop the stranded gas. Presentations made during the public hearings and roundtable discussions suggested that once the gas pipeline is placed in operation, the need for fiscal certainty will evaporate. Locking in terms on taxes and regulatory matters for 35 or even 45 years is antithetical to our form of representative government. Perhaps this is why fiscal regimes in the thirty member-countries of the Organization for Economic Co-Operation and Development (OECD) do not grant stability in any form. In short, the extreme length of the term of this Contract is contrary to the SGDA and antithetical to our democratic form of government.

The SGDA precluded consideration of oil taxes and concessions as part of the Contract. While modernizing the State's oil tax/franchise regime should be given fair consideration on its own merits, no convincing argument has been raised to tie such modernization to development of a gas pipeline under the SGDA. There is no other regime in the world that has granted such "retroactive" stability on existing production. In fact, Dr. Pedro van Meurs stated in a memo dated July 19, 2005 that he knows of no other case where fiscal stability was granted to petroleum that was external to the contract. In addition, he points out that the vast majority of the worldwide production of ExxonMobil, BP, and ConocoPhillips does not have the benefit of any fiscal stability.

The Administration's findings as to why certainty on oil is necessary fail to make a convincing argument. The claim that the State will use dissatisfaction with its fiscal bargain as an impetus to raise oil taxes fails economic logic. Higher oil taxes will discourage development of new oil reserves and, therefore, the associated gas reserves that are needed to fill the gas pipeline in the out years. Why would the State raise taxes on a nearly depleted set of fields in such a way that it would prevent badly needed investment to bring on badly needed reserves?

Oil and gas leases and properties that are included become immune to State regulatory powers (discussed more fully below) and there is no commitment on the part of the Producers to do anything with them or to them—no production commitments, no investment commitments, no commitments at all. The Contract should be limited to only those leases and properties necessary to secure gas supplies to meet shipping commitments on the initial capacity of the pipeline.

In terms of the impact on the economic metrics utilized by the Producers to make their investment decisions on the pipeline, impacts from adjustments in the rate of taxation have the greatest effect in the early years of commercial operations of the Project. As the table below from Econ One Research, Inc.'s presentation to the Legislative Budget and Audit Committee on August 31, 2005 illustrates, even a 50% increase in production taxes has no measurable impact on the Internal Rate of Return—identified as the 'Achilles Heel' of the project in the Commissioner's Fiscal Interest Finding [FIF 168]—by the time you reach the 15th year of commercial operations. Again, long-term fiscal certainty is not necessary once the gas pipeline becomes operational.

Tax Increase After:	Amount of Change Due to 50% Increase to Gas Production Taxes						
	NPV10		NPV10/BOE		Profitability Index10		IRR
	Absolute ($ Billion)	% Change (Percent)	Absolute ($/Bbl)	% Change (Percent)	Absolute	% Change	Absolute (Percent)
5 Years	($0.7)	-3.5%	($0.10)	-3.5%	(0.07)	-2.4%	-0.20%
10 Years	($0.5)	-2.3%	($0.06)	-2.3%	(0.05)	-1.5%	-0.10%
15 Years	($0.3)	-1.4%	($0.04)	-1.4%	(0.03)	-0.9%	0%
20 Years	($0.2)	-0.7%	($0.02)	-0.7%	(0.02)	-0.5%	0%
25 Years	($0.1)	-0.3%	($0.01)	-0.3%	(0.01)	-0.2%	0%

*Assuming $6.00 Price in $2004

Work Commitment

As discussed above, the sole purpose of the SGDA is construction of a pipeline that will lead to development of stranded gas. Commitments by Applicants under the SGDA to construct a pipeline provide the *quid pro quo* for the State's grant of fiscal certainty. Unfortunately, under the Contract, there are no work commitments, construction commitments, funding commitments or capacity shipping commitments.

The Contract contains only two stated obligations related to such required commitments, both under Article 5.2, which describes the Project's implementation. The first is to "begin Project planning not later than 90 days after the Effective Date" of the Contract. The second is to "continue to pursue implementation of the Qualified Project Plan until Project Sanction." Even for these two generic obligations there are no standards, timetables or performance measures.

Worse, the State has no rights to require the Producers to specifically perform even these two nebulous tasks. Instead, the Contract provides but one unsatisfactory remedy. If the State is not satisfied that the Participants have acted with Diligence (a non-standard left completely subjective), then the State can terminate the Fiscal Contract, but only after proceeding through an onerous review process heavily stacked against the State. Problematically, the termination right applies to a Participant acting Diligently, while the Contract delegates responsibility for implementing the Qualified Project Plan to the Mainline Entity.

Under that review process, if the State gives notice of termination, any Participant may dispute the proposed termination and the dispute will be determined by arbitration. In the arbitration the legal presumption is that the Fiscal Contract should not be terminated, the State's presumption of correctness and entitlement to deference is waived, and the State has the burden of proof to demonstrate:

- by "clear and convincing evidence" (not the industry norm contract dispute preponderance of the evidence standard)
- that the Participants are not acting with "prudence under the circumstances" in conducting the Project planning activities, and
- that the lack of such planning has resulted in a "material adverse impact on the Project" (lack of planning alone will not constitute a lack of "Diligence")

In making its decision the Tribunal:

- must consider the Participants' commercial and regulatory difficulties and delays; but may not consider any Participant's errors in judgment, any Participant's unwillingness to enter into a contract or settle a dispute, or any suspension of a Participant's planning activities due to force majeure or legal challenge of the Fiscal Contract

This termination process makes the State's ability to actually terminate the Fiscal Contract virtually impossible. With no specified work, construction, or supply commitments, doing nothing could be interpreted as Diligent under this standard.

In summary, the "work commitment" merely requires commencement of planning, with no requirement even to generate sufficient Project information to enable the Participants to make a decision whether to make a commitment to build the Project. The "work commitment" obligation is delegated to the Mainline Entity, which is extraneous to the Contract, and which is given authority to change the Qualified Project Plan without standards or limitations on such right and without the State's consent. The State's sole remedy for the participant's failure to perform the "work commitment" is termination of the Fiscal Contract, but the termination process is so draconian that the remedy is for all practical purposes unavailable. The effect of all this is to bind the State to its obligations under the Contract interminably, without ever requiring the construction of a pipeline, and without any recourse to the State to avail itself of alternatives—including potential competing projects that are able and willing to make firm commitments to a more timely schedule.

As to whether or not the amorphous work commitment contained in Article 5 will deliver the construction of a natural gas pipeline, one need look no further than the history of the PTU. The lessee's unwillingness to honor prior, explicit work commitments is clear and unambiguous from the record. Actions speak louder than words. Why should the State expect better results from an ambiguous standard and a fully-amendable QPP?

"Diligence"

"Diligence" is not a work commitment; it is a standard by which commitments would be measured. Industry custom and practice normally relies upon standards of due diligence and/or a prudent operator standard (*i.e.*, what a prudent operator would do under the circumstances) as a means to measure the quality of performance and intent to perform against specified work and other commitments within contractually prescribed time frames.

The Diligence standard provided for in the Contract emasculates industry standards. It does not employ a due diligence or prudent operator standard. Instead, it specifically protects against errors in judgment, whether such errors would violate a due care standard or not. This standard can be contrasted with "due diligence," which is often provided in contracts in the industry. Due diligence (also known as due care) is the effort made by an ordinarily prudent or reasonable party, and not the subjective party at issue. Failure to make this effort is generally considered negligence and is not limited by "errors in judgment" and other factors that it actually seeks to include. "Diligence" as a defined performance standard in the Contract is not in accord with industry custom and practice and presents a lower threshold than is customary.

Qualified Project Plan

The State has a substantial interest in ensuring that the Qualified Project Plan (QPP) in effect remains consistent with the QPP in effect when the State made its binding commitments to the Producers.

In the Contract there are no standards or limitations on the types of changes that could be made in an amended QPP or the process for changing the QPP. The Mainline Entity has been delegated the authority to change the scope of the work commitment, the timeline for performance of the work commitment in the Qualified Project Plan at any time, and even the parameters specifications for the design capacity of the pipeline. Faced with a claim of lack of Diligence, the Mainline Entity could simply change the QPP to eliminate the claim. While the State and Producers may be aligned on the desirability of getting a pipeline, the parties' interests may diverge on the issue of timing and acceptable conditions and economics.

While the Producers and the State will rightly pursue their own entity interests and will not have a consistent, unified position on many issues, the risk to the State remains that a majority of the Producer group could well coalesce on changing a critical QPP provision to the detriment of the State. Each Producer faces this same risk of a coalescence of an unexpected majority interest. This lack of alignment may be further exacerbated because the commercial objectives of the State's member in the Project Entity are unlikely to be aligned with the sovereign objectives of the State.

It has been suggested that the State could initiate a "dispute" if it believed the Producers were not acting in good faith. Acting in good faith is not one of the standards that would permit a termination. Nor can the dispute resolution process be used to compel a participant to start acting in good faith, as there is no specific performance remedy allowed. Reliance on the dispute resolution process does not work for QPP changes.

Force Majeure

An overly broad Force Majeure excuse from performance and the exclusions to "diligence" constitute wide, expansive loopholes to excuse the non-performance of the already weak obligations of the Producers. For instance, the definition covers the "inability to perform an obligation," but has no materiality qualifier.

It excuses non-performance for "an event, whether foreseen or not, that is beyond the reasonable control" of a party. This inclusion is in direct contravention of the typical limitation that the party must have used reasonable foresight, planning and implementation in order for the event to be force majeure.

It further has no critical path qualifier, allowing any peripheral non-material Force Majeure to delay a Participant's overall performance. The definition for a Force Majeure Event includes activities which are typically <u>not</u> force majeure events such as, "any judicial acts or restraints;" "…inability to obtain necessary material in the open market for delivery of those materials to the site of use", and "lockouts" (which are in the control of the Participants). It also fails to include a diligent action qualifier for subpart (d), which is included for subparts (c) and (e).

State In-Kind Taking of Gas (Royalty and Tax)

The State's agreement to take its gas in-kind under the set of parameters negotiated under the Contract represents a major departure from the precedent, procedures and protections afforded by State statutes, regulations, lease provisions and unit agreements.

While state statutes generally favor in-kind taking, they also establish limitations on the Department of Natural Resources' (DNR) authorities to enter into in-kind sales of oil and gas. The DNR's regulations, 11 AAC 03.015, establish conditions that must be met in any in-kind taking of royalty oil, gas or associated substances, and 11 AAC 03.250 and 11 AAC 88.185 define gas for the purpose of in-kind dispositions. Collectively, these provisions are designed to assure that, if the State elects to take all or a portion of its oil and gas in-kind, it is to receive the resource in merchantable quality and free of any "field costs."

The requirement for the State to take all of its royalty gas in-kind for the duration of the Contract also marks a major departure from several policies that have guided previous in-kind sales by the DNR, which are designed to protect the State's fiscal and legal interests. Those policies were: 1) to retain a percentage of the available royalty share in value to assure that, in taking some of its royalty gas in-kind, it would receive no less from its sale than it would have received had it taken the sale volume in-value; and 2) to never take actual, physical custody of the State's in-kind share, and thus, to avoid the legal and fiscal risks inherent in the very complicated transportation, marketing, and downstream sales arrangements that doing so would entail.

To insulate itself from the financial and legal risks inherent in physically taking custody of its royalty share, the State has consistently included two provisions in its in-kind sales agreements. The first makes the purchaser's receipt of the State's royalty share occur instantaneously upon the transfer of custody from the producer. The second makes it the purchaser's obligation to take the full volume of its percentage share of the State's royalty share obligation.

The State's commitment under those contracts was to convey a specified percentage of what it was to receive from the producer, with no guarantee to its purchaser of what the absolute volume was to be, and the purchaser's obligation was to take custody of that volume and to be responsible for its transportation, marketing and ultimate use. These protections, provided by the policies that have been in place for almost thirty years, will be forfeited under the provisions of the Contract.

The Contract provides that the State will take its in kind share of production effectively in the field. This requires that the State take on the risk associated with capacity management, which is profound and difficult to quantify. Certainly, the State's duty to satisfy supply contracts in downstream markets increases the risk and cost of managing the State's gas portfolio.

Compounding these risks is the absence of a supply commitment on the part of the producers. There is no obligation in the Contract on the part of the producer Participants to commit reserves, develop fields, deliver volumes, or maintain deliverability to the Project. Committing to make reservation payments (demand charges) under FERC rates is not an obligation to produce. The contractual obligation to support the pipeline is separate and distinct from field operations. The economics, timing, and strategy for production carry a distinct set of economic and commercial drivers apart from the pipeline. Once committed to, the producer Participants will view the pipeline and related investments as sunk costs and will make production decisions that maximize their positions accordingly, just as they would if a third party pipeline were put into service in lieu of the Project discussed in the Contract.

The State will be competing with the producer Participants in both the natural gas commodity markets and in the pipeline capacity markets by taking delivery as specified in the Contract. This creates a distinct diversity of interest among the parties that magnifies the risks of a minority interest holder who has no control over production and will be at an inherent disadvantage in obtaining timely development, production, and operations information.

It should also be noted that Article 10.10 provides that "At all times after the Effective Date, the State shall indemnify, hold harmless, and defend each Producer and Producer Capacity Holder against any Loss arising out of or resulting from a Producer Capacity Holder's performance of or failure to perform an obligation under Article 10 (Capacity Management), except in case of fraud." The State is effectively backstopping the producer Participants against their own actions.

The issue of capacity management has tremendous complexity. Depending on the configuration of the system, there will be several types of capacity that the State must manage. These include capacity on the Gas Transmission Pipelines, capacity through the GTP, and various "chunks" of capacity from the discharge of the GTP to each point at which the State will be delivering its gas (*i.e.*, the four or more in-state take-off points, as well as the delivery point at the Alberta hub and, potentially, other delivery points up- and down-stream from that hub, as well as a possible delivery point at Chicago).

As to each of these pipeline/processing/system segments and delivery points the State's gas company will have to nominate and schedule gas pursuant to industry standards. Those standards now establish at least four scheduling cycles for gas flows per day. Thus, if the State is receiving gas from multiple wellheads, flowing into each of the contemplated Gas Transmission Pipelines, the State will have to match its gas flows from the wellheads through the Gas Transmission Pipelines to the GTP and do so during each of the four daily scheduling cycles. Capacity in each line that the State can't fill with gas in 8-hour cycles reflects wasted money. Likewise, any of the State's gas that can't be matched to available capacity through the Gas Transmission Pipelines during each of those scheduling cycles will represent lost value to the State. Thus it is imperative that the Contract structures work as intended.

The foregoing description of the stakes that are involved in holding and managing capacity only cover the first leg of the system. Gas will have to be scheduled through the GTP. So far, there are no procedures that would dictate how that will be done. But even once the gas reaches the mainline, the State must still ensure that it has adequate gas (and adequate capacity) from the GTP to each of the points at which the State will sell its gas. Overage or underage at any point along the way, during any daily 8-hour nomination and scheduling cycles, will represent lost value to the State.

The further upstream that the State actually takes gas and assumes the responsibility for managing its gas and capacity, the more complex capacity management becomes. The State's gas is going to come from multiple wells and multiple fields; some days gas will be shut in at some and flowing at others. These flows may change daily or even within each so-called "gas day." With each change in source of production comes a potential difference in the royalty terms—and ultimately the volume of State Gas to be delivered to the State Capacity Holder. Against this backdrop, the State's gas company (or its capacity manager) will have to be nominating and scheduling capacity on the relevant pipelines and through the GTP and mainline on 8-hour cycles. When (and more importantly, where) the gas shows up, there must be available capacity in the system or else the State has lost value.

The Administration contracted with the Lukens Energy Group to try and ascertain the magnitude of the risks associated with taking on the obligations of capacity management. Lukens estimated that the range of uncertainty is quite broad and may result in a reduction to the State's net present value up to of 11%.

The Administration and the Producers have clearly worked very hard on the Capacity Management provisions of the Contract (Article 10). Essentially, the Contract appears to require that the parties provide gas or capacity as necessary to each other to ensure that the State's gas moves to markets at all times. This should significantly reduce the State's risk exposure and minimize lost value. Without the protections of Article 10's Capacity Management provisions, the choice to take all of the State's royalties in-kind as well as the production tax value in-kind could be catastrophic.

According to the Administration, the same provisions in Article 10 that protect the State when State Gas volumes fail to meet, or exceed, State Capacity are in conflict with established FERC policies. The exclusive right of the State and the Producers to move capacity back and forth to each other is problematic. FERC rules call for a transparent, open market place for what is called secondary market capacity—capacity that holders do not need on a short- to long-term basis. The regulations call for posting of capacity available for release and for announcing in advance the terms under which bidders for such capacity can compete to acquire that capacity. Article 10 seems to require that the State deal exclusively with the Producers. This could disadvantage other shippers or potential shippers.

Contract terms will be subject to review by FERC for its compliance with FERC's policies and practices. If Article 10 is found to be inconsistent, as is expected by the Administration, specific action would need to be taken by FERC to modify its policies. While it would appear quite likely that FERC will take extraordinary steps to facilitate the Project, other shippers—or potential shippers—would likely dispute a policy that allows the State to deal exclusively with the Producers. Article 10.8 stipulates that if the FERC, NEB, US Department of Justice or a court finds any provision of Articles 10.1, 10.2, 10.3, or 10.4 to be contrary to *Law* then those articles terminate and the parties are supposed to negotiate a mutually acceptable alternative provision that remedies the defect.

Costs to State: Costs/Deductions/Allowances/Credits

While the Administration, the Producers, legislators, consultants and the public can argue over whether or not the State revenues under the fiscal terms of the Contract will be substantially the same as under the terms provided under current state law, it is inarguable that the State has given up rights, made commitments, and relinquished obligations under the terms of the Contract. These are, by definition, concessions.

One of the most challenging parts of this process has been to identify and quantify all of the concessions. The following is a compilation of various categories of concessions identified to date:

- State Participation in Project Entities;
- Stability on Oil;
- Stability on Gas;
- Limiting recourse in disputes to arbitration;
- Surrender of the State's enjoyment of deference in the courts;
- Allowing oil valuation regulations to be re-negotiated and subject to arbitration;
- Commitment Allowance (GTP and Transmission Line credits);
- Upstream Cost Allowance;
- PPT deductions, credits and allowances (gas investment reduces oil taxes);
- Capacity management costs;
- Marketing costs;
- Loss of "higher of" in value computations under State's O&G lease forms;
- Loss of option to take in value or in kind under State's O&G lease forms;
- Costs of "impurities" (separation and disposal);
- Potential reimbursement and indemnity for Producer Costs

Some of these concessions and their impacts to state revenue can be quantified. Some cannot—or their cost will be determined by some future agreement(s). One thing is clear: the scope of these risks and fiscal effects is unprecedented in the history of the State's management of its subsurface interests. Considering the written record and testimony of Dr. Pedro van Meurs[4], it appears the Contract's terms are unprecedented in world history as well.

Some of the concessions appear to be borne out of the Administration's decision to take the royalties and taxes in Gas. Unfortunately, these types of concessions have quantifiable costs to the State, but have almost no measurable effect on the economic metrics for the Producers. You can see the contrast in effects from the table prepared by Econ One Research, Inc. for the Legislative Budget and Audit Committee and presented on June 14-15, 2006:

[4] "International Fiscal Stability" Pedro van Meurs, July 19, 2005.

	Summary of Impacts of Fiscal Terms	State Metrics					
		Net Revenues ($2005)			NPV - 8		
		Total	Effect of Change	% Change	Total	Effect of Change	% Change
		(Million $)		(Percent)	(Million $)		(Percent)
	Proposed Contract	$ 52,833	-	-	$ 14,664	-	-
1	State Ownership of Pipeline	$ 51,422	$ 1,411	2.7%	$ 14,261	$ 403	2.8%
2	PPT System Severance Tax Rates	$ 64,039	$ (11,206)	-17.5%	$ 17,915	$ (3,251)	-18.1%
3	ELF System Severance Tax Rates	$ 52,269	$ 564	1.1%	$ 14,593	$ 71	0.5%
4	ELF System Tax Rates and Deductions/Credits	$ 55,853	$ (3,020)	-5.4%	$ 15,633	$ (969)	-6.2%
5	Remove GTP/Feeder Contribution Credits	$ 53,729	$ (896)	-1.7%	$ 45,275	$ (611)	-4.0%
6	Remove Take-In-Kind Costs	$ 53,943	$ (1,110)	-2.1%	$ 15,008	$ (344)	-2.3%
7	Change to UCA Per SQ	$ 54,265	$ (1,432)	-2.6%	$ 15,082	$ (418)	-2.8%
8	Change to GTP Deductions Per SQ	$ 53,227	$ (394)	-0.7%	$ 14,786	$ (122)	-0.8%
9	Change to Property Tax Per SQ	$ 53,966	$ (1,133)	-2.1%	$ 15,248	$ (585)	-3.8%

		Producer Metrics (Combined Upstream and Midstream)						
		Net Revenues ($2005)			NPV - 10			
		Total	Effect of Change	% Change	Total	Effect of Change	% Change	IRR
		(Million $)		(Percent)	(Million $)		(Percent)	(Percent)
	Proposed Contract	$ 127,452	-	-	$ 21,228	-	-	27.0%
1	State Ownership of Pipeline	$ 129,301	$ (1,849)	-1.4%	$ 20,823	$ 404	1.9%	24.5%
2	PPT System Severance Tax Rates	$ 120,152	$ 7,300	6.1%	$ 19,792	$ 1,436	7.3%	26.2%
3	ELF System Severance Tax Rates	$ 127,825	$ (373)	-0.3%	$ 21,249	$ (21)	-0.1%	27.0%
4	ELF System Tax Rates and Deductions/Credits	$ 125,518	$ 1,935	1.5%	$ 20,788	$ 440	2.1%	26.6%
5	Remove GTP/Feeder Contribution Credits	$ 126,870	$ 582	0.5%	$ 20,880	$ 348	1.7%	26.2%
6	Remove Take-In-Kind Costs	$ 127,034	$ 418	0.3%	$ 21,138	$ 90	0.4%	27.0%
7	Change to UCA Per SQ	$ 126,530	$ 922	0.7%	$ 21,045	$ 183	0.9%	26.9%
8	Change to GTP Deductions Per SQ	$ 127,199	$ 254	0.2%	$ 21,173	$ 54	0.3%	27.0%
9	Change to Property Tax Per SQ	$ 126,636	$ 816	0.6%	$ 20,922	$ 306	1.5%	26.7%

*Assuming $6.00 gas price in $2005

The impacts to the project's "Achilles Heel" metric—Internal Rate of Return—are driven almost entirely by the State's ownership interest in the Pipeline. The second largest impact to Producer metrics is the deductions and credits afforded the Pt. Thomson Unit developers. Consequently, it does not appear that many of these concessions are reasonable or necessary.

In an arrangement predicated on the idea of State participation and shared ownership of facilities, the inclusion of credits for the GTP and Transmission Lines seems out of place. Contributing capital through such credits without retaining additional ownership rights in such facilities through entity agreements is mind-boggling, particularly with regard to facilities that could become chokepoints in the overall transportation system.

The question of whether FERC or RCA will regulate these particular facilities (discussed at greater length below) for terms of service and access is unknown at this time. Without regulation, there is nothing to prevent the exercise of monopoly power in the negotiation of commercial agreements for access by other producer explorers. This could stymie additional exploration and development in areas east and west of the existing infrastructure at Prudhoe Bay. Additional State ownership rights—and, therefore, control of the facilities—could mitigate this uncertainty.

Even with FERC or RCA regulation, there is no binding precedent that would require the benefits of credits such as these to be flowed-through to third party customers. When the cost of service is reduced, it results in higher net-back values. Higher net-back values result in lower costs of development for new fields and discoveries. If the State is going to contribute public capital towards the construction of these facilities, then it is appropriate to condition that contribution on sharing the benefits of that capital with all customers of the facilities—including the State.

Pt. Thomson Development Obligation Suspended and Removed from DNR Control

The provisions of Article 23 relating to the Point Thomson Unit (PTU) represent a major policy decision for the State of Alaska. Essentially, the Legislature is being asked to give up the Commissioner of Natural Resources' authority to administer the terms of the State's oil and gas leases, and that decision is intended to extend well beyond the leases in the PTU. All obligations are deferred indefinitely and DNR's orders with respect to the PTU are specifically abrogated. The DNR is <u>prohibited</u> from:

- Enforcing the Expansion Agreement;
- Terminating the PTU or any Property within the PTU;
- Enforcing any obligations the PTU Owners prepare, and obtaining approval of the DNR of a plan of development ("POD"); or
- Altering or modifying the rate of development or operations for the PTU

In addition, the obligation on the part of the lessees to commit its share of 500 million cubic feet per day of PTU Gas to the Project is premature. The AOGCC has yet to determine whether gas cycling is necessary to maximize hydrocarbon recovery. Considering only the conservation of Alaska's hydrocarbon resources, Point Thomson should be developed as an oil field. To maximize both oil and gas recovery, gas from Point Thomson should be re-injected back into the reservoir until all of the economically recoverable liquid hydrocarbons have been produced. Merely making application to the AOGCC does not relieve the lessees of their obligation in Art. 23.1(a) and 23.1(b). Nor does it limit the prohibitions on DNR's powers to alter or change development at the PTU. This ensures that the PTU Owners will be free to develop the reservoir as they see fit—regardless of the interests of the State.

Expansions and Cost of Service

The Contract fails to address expansion issues adequately. It fails to address voluntary expansions at all. It fails to commit the parties to use rolled-in pricing for looping-based expansions, it fails to provide the State with any right to expand the Pipeline at its sole risk. Lastly, to the extent the Contract does address expansion—in the "State-initiated expansion" section appearing at Article 8.7—the Contract erects numerous barriers to expansion.

The State and the Producers may be aligned on the desirability of getting a pipeline. On the issue of expansion, though, it seems clear that the State and these three producers are not aligned. The State clearly favors expansions of the line to promote access for all explorer producers. However, these explorer producers are the direct competitors of the Producers who will be majority owners of the line. Consequently, on expansion issues, the State, in furtherance of its policies of encouraging development of resources and maintaining a level competitive playing field for all stakeholders, will clearly favor early expansion of the line and its eventual build-out to its ultimate capacity somewhere between 8 and 10 Bcf/day. The Producers' needs, though are to move <u>their</u> gas to market and they have no particular interest in having the line expanded, especially if such expansion will serve their competitors or may put downward pressure on gas prices in destination markets by increasing overall gas supply.

The FERC has gone to great lengths to limit market power and prevent discrimination in the provision of service on natural gas pipelines—particularly when a pipeline is owned by an entity or entities that are affiliated with the shippers that use the pipeline. Concerns such as these led to efforts at the FERC to restructure the natural gas transportation industry in the mid-1980s and early 1990s. Orders 436, 636, and 2004 took incremental steps towards minimizing the effects of market power and monopoly practices. All of these orders, though, relate to service on operating facilities. The problem with these regulations is: they have *nothing* to do with whether a pipeline company will agree to expand its system.

While expansion is vital from the State's standpoint, it may not be a high priority for the Producers, and they may even view expansions to be antithetical to their best business interests. Thus it seems imperative that the State obtain agreement from the Producers now on expansion issues since it is now that the State is granting its many fiscal concessions to the Producers to induce them to build the line.

No affirmative commitment to terms for voluntary expansion

There is a long lead-time between when an explorer producer would start looking for gas and the time at which such a producer would be capable of commercializing its discoveries. Thus it is likely that many explorer producers will not be in a position to bid for capacity in the initial open season for the pipeline. Without periodic expansions of the line, these producers will be forced to wait 20 or more years—until the expiration of the initial shippers' contracts—for access to the line. This would not be a desirable result from the State's standpoint. Early expansion of the line will be critical to the ultimate exploitation of the State's vast resource base.

Unfortunately, the Contract is completely silent regarding future voluntary expansions of the line. This absence is very problematic given that the project sponsors are themselves gas producers and do not have the same economic motivation to favor expansions as does the State or as would an independent pipeline company.

Without question, FERC will be the entity that determines in the final instance whether to approve an expansion and, if approved, what rate structure will apply to that expansion capacity. Prior to the FERC making a decision, the pipeline sponsor (in this case the Mainline Entity) determines what to ask the FERC to approve and will have to make the case for the public convenience and necessity of its project and the justness and reasonableness of its proposed rates. Parties who intervene in the proceeding will be free to challenge any and all aspects of the applicants' proposal. In the end, FERC can approve something different than what the applicant proposed, and can impose conditions on its certificate authority, and in such event the pipeline company is free to reject the certificate if it does not like the terms imposed. However, it is up to the Mainline Entity to propose expansions and expansion terms to the FERC

There are several aspects of voluntary expansion that should have been included in this agreement. It is reasonable for the State to establish as part of the contract the terms and conditions under which the Mainline Entity will: 1) hold periodic open seasons (even non-binding open seasons) to assess the market for new capacity; 2) agree to expand the pipeline; 3) file to certificate such an expansion; and 4) propose to price the expansion capacity. As to these activities the FERC will not act as surrogate for the State and its interests. Therefore, it is appropriate—and perhaps obligatory—for the State to require parties to address in advance the terms and conditions upon which the Mainline Entity will undertake the expansion applications. Including voluntary expansion terms in the Contract itself would be even more prudent given the apparent difficulty the parties seem to be having finalizing the LLC agreement.

The Need for Expansions

On the general issue of expansion, it has frequently been stated that there are not enough identified gas reserves to fill the first phase of the pipeline, and, accordingly, concerns about expansion of the pipeline are premature. However, it is deliverability, not reserves, that is the important factor to consider in the context of expansion. There are some 30 Tcf of proven reserves on the North Slope. The Prudhoe Bay reserves have a deliverability of over 8 Bcf/day (AOGCC approved off-take rates notwithstanding).

While the Administration and the Producers are technically correct that more gas is needed in the out years if the line is to be used for a full 25-35 or more years, this speaks to reserves. Once the line is built the level of deliverability of wells and fields feeding the line will be as significant an issue as the size of the ultimate reserve base.

Once the line goes into service any producer who brings new gas deliverability to the pipeline (whether or not it adds to the reserve base) will likely need to have expansion capacity created in order to move its gas to market (assuming the line is fully contracted at the outset). The alternative approach for such a producer is that they will have to hold their gas until the initial contracts on the line expire or until the current 30 Tcf of reserves are depleted (in approximately 20-25 years), and then ship its gas. Certainly, this does not encourage the exploration and development of Alaska's gas resources.

From other pipeline project experiences, a scenario can easily be envisioned in which gas will be commercialized between now and the in-service date that will require an expansion to be undertaken, before or shortly after the original line is fully operational. This results from additional deliverability upstream of the pipeline—whether or not there are additional reserves.

While it is important to find a contract structure that will encourage discovery of additional proven reserves for the out years of the contract, it is also critical that the contract structure address expansion concerns for the near- and mid- range years of the contract. In this regard, anything that encourages exploration and results in increased deliverability may well lead to the addition of reserves to the known and proven category—thus decreasing the long-term risk to the owners. The way to encourage exploration is to assure the companies that will undertake such exploration and development efforts that the gas they discover will have access to the pipe when the production starts—not 20 or more years after the pipe goes into service.

Because the Contract contains no provision dealing with the terms under which the line would be expanded voluntarily, expansions of the line cannot be assured. This is a material deficiency in the Contract. If such provisions had been included, many of the concerns about access by explorer producers could be eliminated, and some of the concerns arising from the failure to provide the LLC agreements for legislative review and approval would be reduced.

Expansion Pricing

The Contract does not commit the parties to any form of pricing for expansion capacity. Rolled-in pricing is crucial to the ultimate capacity of the pipeline (and hence the commercialization of all the State's gas resources). It is generally held that the line can be expanded to a capacity of about 6 Bcf/day through the addition of compression. Such expansions will generally reduce the unit rate for service on the line. However, to expand beyond the 6 Bcf/day level, more expensive looping will be required. Unless this additional capacity is priced on a rolled-in basis it will be prohibitively expensive—perhaps twice the rate for the then-existing system users.

The FERC has established a rebuttable presumption in favor of rolled-in pricing for voluntary expansions of the Alaska pipeline—an important departure from their policy in the Lower 48. There, FERC now requires that pipeline expansions and extensions be priced incrementally whenever rolled-in pricing increases the rates to existing shippers.

This policy, however, is based on concerns surrounding pipelines competing for new markets and is designed to ensure that incumbent pipelines competing with other pipeline companies do not have an inherent competitive advantage by being able to roll-in the cost of new facilities and thus mask the true cost of providing the new service. The Alaska line, however, will be a monopoly and the FERC concluded that its Lower-48 policy had no applicability on this pipeline.

It is worth noting that the Producers opposed FERC's adoption of its presumptions in favor of rolled-in pricing and included that aspect in their original appeal of Order No. 2005. It is reasonable to assume that the State's Producer-partners may again be disinclined to aggressively advocate and defend rolled-in pricing if it might increase their affiliates' shipping rates. Clearly, the final decision on the rate structure for voluntary expansions will be made by FERC notwithstanding a provision in the Contract requiring rolled-in pricing. However, a commitment by the Producers to propose and defend rolled-in pricing sets the stage for what FERC will ultimately require. It may not guarantee that FERC will approve rolled-in pricing in any given set of expansion circumstances but it is an important first step in maintaining the "victory" that the State won on this issue when FERC established its presumption in favor of rolled-in pricing in its open season rulemaking.

Given that rolled-in rate treatment is vital to the ultimate exploitation of the State's gas reserves, the silence of the Contract on this issue represents a fundamental defect in the agreement. This is especially true in light of the length of the term of this contract—as long as 45 years. While expansions utilizing the more-expensive looping (beyond the 6 Bcf/day estimated is available through compression) is unlikely to occur in the near- or medium-term, the Contract must address those issues that can reasonably be expected to confront the interests of the State in that timeframe.

Restrictive "State Initiated Expansion" provision

The Contract includes a lengthy provision under which a potential shipper who has been unable to secure capacity can request that the State cause an expansion to be undertaken on that shipper's behalf. Unfortunately, there are so many conditions that must be satisfied under this mechanism that it provides little reason to expect that it will result in an expansion.

To appreciate the limits of this Article, it is necessary to understand the terms under which FERC can mandate expansion of the Alaska pipeline. Prior to enactment of ANGPA the FERC had never had the authority to order the expansion of any pipeline over the objection of the line's owners. Thus the new authority granted to FERC by ANGPA is significant.

Nonetheless, before it can order an expansion, FERC must satisfy 8 conditions:

- Rates must recover costs (including return on investment)
- Existing shippers must not subsidize expansion

- Expansion shippers will comply with existing tariff
- Facilities will not adversely affect financial or economic viability of project
- Facilities will not adversely affect overall operations
- Proposed facilities will not diminish contract rights of existing shippers
- All environmental reviews must be completed
- Adequate downstream capacity must exist or be expected to exist

Article 8.7 of the Contract, however, includes 10 more conditions:

- Must not require existing shipper to pay a higher rate than without an expansion
- Must not require existing shipper to be assessed a higher fuel retention percentage than without expansion
- Only available every 5 years
- Minimum volume (50,000 Mcf on Gas Transmission Lines/ 125,000 Mcf on Mainline)
- Does not require Mainline Entity to construct lateral from the Pipeline
- No more than 100 miles of looping
- Minimum volumes exclude producer affiliate volumes but rate calculations must include producer affiliate volumes
- Expansion shipper must meet creditworthiness standards of tariff
- Expansion shipper pays in advance its share of costs related to certificate application
- Expansion shipper obligates itself to pro-ration in open season

Given these many conditions—which are even more restrictive than those that constrain the FERC in ordering a mandatory expansion—this provision of the Contract does little to assure explorer producers that they can obtain expansion capacity through this vehicle.

An expansion could more easily be obtained under the mandatory expansion provisions of the Federal statute (with only 8 requirements) than under 8.7 (with its 18 requirements). Further, by utilizing the Federal statute, the new customer would be assured of obtaining the capacity rather than having to bid for it in a subsequent open season as is required in 8.7. Additionally, by using the Federal statute rather than the "State-initiated expansion" provision, the shipper would not have to advance 100% of the costs of engineering and designing the expansion as well as the cost of the environmental reviews and the cost of the regulatory applications as required by 8.7. It must simply be recognized that 8.7 does not provide a meaningful opportunity for expansion of the line.

Value of Previously used assets

Article 8.6 of the Contract is quite short, but potentially costly to all shippers on the pipeline—including the State. This article provides: "Each Participant shall follow FERC policy regarding treatment of previously used assets for FERC ratemaking purposes." The significance of this article arises in the context of the potential inclusion of the original costs (or even some potentially higher acquisition cost) of the existing central gas facility at Prudhoe Bay in the rates of either the GTP and/or an NGL plant. This plant cost approximately $1 billion at its construction. It will be largely depreciated by the time the gas pipeline goes into service.

FERC's policy generally precludes one regulated entity from writing up the value of assets required from another regulated entity. FERC typically requires that the new owner include only the net book value of such assets in its rate base. However, an exception exists where the asset has previously not been used for utility service or has been used for other services, with different customers (e.g., an oil pipeline being converted to gas service). In that case the previously used asset can be included in rate base at its acquisition cost. FERC's rationale is that there is no "double recovery" of depreciation costs since the new group of customers will not have been paying for the depreciation when used by a different group of customers. Thus, because this facility has not been used in gas utility service, Article 8.6 of the Contract could well result in as much as $1 billion (or even more if the facility is valued at its replacement cost or some as yet unknown acquisition cost) being included in rate base for part of the pipeline system.

Econ One has estimated this figure could result in an increase of roughly $0.10/Mcf to the cost of shipping on the Project. Since Prudhoe Bay owners will be selling the asset to an LLC owned 80% by their affiliates, the issue of purchase price might be an issue at FERC. However, whatever level of purchase price the FERC ultimately establishes as reasonable, a substantial cost burden could be placed on system users by relying on "FERC policy."

Article 8.6 does nothing to reduce the cost of service for the Alaska pipeline system. Instead, it creates an opportunity for the Producers to argue for a substantial write-up in the value of all previously used assets that are converted to gas pipeline service. If this is not intended, it should be clarified in the Contract.

No Commitment to Supply In-State Volumes

Having the opportunity for four off-take points without commitments—or obligations—to sell gas to in-state customers is kind of like—no, worse than—having an oil pipeline run through your backyard and still have to pay some of the highest prices in the nation at the gasoline pump.

It appears that the State Gas will fill In-State volumes, but that carries a whole host of problems with it. The timing of the initial Open Season presents some problems due to interrelations with Article 10. Under Article 10.1, the State must provide notice to Producer Capacity Holders at least 30 days before the close of the Mainline's Open Season. In order to facilitate in-state demand, there will need to be open seasons for each of the four off-take points referenced in Article 9. If the commitments at those open seasons are not sufficient to meet projected demands found by studies required under FERC's guidelines on the conduct of the Mainline open season, the State will face the horrible choice of "stranding" capacity downstream of the last in-state off-take point or failing to deliver sufficient quantities to satisfy in-state demands.

The State may have to rely upon its share of volumes in future expansions to meet rising demand as infrastructure develops around the pipeline corridor and near the four off-take points. Will there be expansions? Will the State's share of those volumes fill the demand? Compounding the problem is the fact that the State has not made any in-state pricing policy decisions yet—it will be a pitched battle between those who are able to gain access to the gas and those in remote locations who will never be able to gain access.

Regulatory Suppression

Alaska's oil and gas arrangements use a lease structure, generate government take through a royalty tax regime, and are managed and controlled through comprehensive regulation. The SGDA does not appear to contemplate that any right or privilege of any Participant in any lease, agreement, regulation, rule, order, or decree would be modified to conform to a Fiscal Contract. Nonetheless the Contract contemplates that the rights and privileges of the State would be modified to a disturbing agree.

Note that the SGDA (Sec. 43.82.220(a)) limits the impacts that a fiscal contract may have on provisions of leases and unit agreements:

> "modify the timing and notice provisions of leases and unit agreements pertaining to the State's rights to receive its royalty in kind or in value…".

However, it is clear the Contract will affect both leases and unit agreements. To that end Article 41.2 provides that:

> "After the Effective Date, any right, privilege or obligation of a Party in a lease, other agreement, regulation, rule, order or decision ("Document") is amended for the Term only to the extent necessary to conform to the provisions of this Contract. If there is a Dispute regarding whether this Contract and another Document create conflicting rights, privileges or obligations, the Parties shall attempt to resolve the Dispute in good faith by attempting to harmonize them, giving reasonable effect to both. If the Parties cannot harmonize them, <u>this Contract controls</u>."

Because the Fiscal Contract is so broad in its scope and specifically refers to so many entities, leases, properties, assets, and types of activities, the impact of this conforming provision on the State's regulatory regime would be very far reaching and will probably have many unintended consequences.

This is not by accident; the Contract is intended to be a broad and far-reaching agreement. With regard to the effect of State participation on State laws and regulations, Article 41.1 provides in part that:

> "…the State's equity participation in any project does not restrict or otherwise limit the State's sovereign power to regulate the Project under applicable Law."

Notwithstanding that the State's participation is not intended to restrict or limit the State's regulatory regime, the express intent of the State and the Producers (recital 13):

> "is to provide protections to the Project and the Participants during the [term of the Fiscal Contract] to ensure the stability and durability of the negotiated terms and conditions."

Under the existing regulatory regime disputes are resolved in administrative proceedings or in State courts. Under the Fiscal Contract all disputes, even administrative and regulatory disputes, would be resolved by arbitration. Article 26.1 provides that:

> "Each Dispute is to be exclusively and finally resolved by the amicable resolution and arbitration procedures specified under Exhibit C …"

The arbitration provisions set out in Exhibit C are complex. Among other matters Exhibit C.8 (b) provides:

> "For purposes of Disputes under this Contract, the Parties waive any defense based upon sovereignty, including immunity to arbitration, and immunity to judicial proceedings to enforce or aid any arbitration with respect to judicial proceedings as provided in Article 26.2."

In summary, the Fiscal Contract would suppress the State's regulatory regime as it pertains to the Project and the properties and activities of Participants for the duration of the Fiscal Contract by requiring the State:

- to endeavor to avoid RCA jurisdiction and to indemnify the Participants from Losses arising from RCA jurisdiction;
- to relinquish its presumption of correctness in interpreting the application of the State's regulatory regime;
- to conform all rights, privileges and obligations under any lease, agreement, regulation, rule, or order to the Fiscal Contract;
- to resolve all regulatory disputes by arbitration; and
- to waive any defenses based on the State's sovereignty.

The specific effect that each of these measures would have from day to day on separate aspects of the State's regulatory regime cannot be accurately predicted. From the perspective of the State, however, the general effect that these measures would have on its regulatory regime with respect to activities under the Fiscal Contract would likely be pervasive and chilling.

Regulatory Commission of Alaska Jurisdiction

All interstate natural gas pipelines in the United States, like electric transmission lines operating in interstate commerce, are subject to federal economic regulation because of the Congressional determination that they are natural monopolies. Since 1938, the Natural Gas Act has provided the primary statutory authority to assure that rates and charges are just and reasonable, and that the services are provided on a not unduly discriminatory basis. Congress continues to believe that appropriate regulation is necessary to address market power concerns.

However, it is unknown at this time whether FERC will have or assert jurisdiction over all aspects of the Project. Historically, FERC has held that processing of natural gas in order to bring it to "pipeline quality" was not within the scope of its authority under the

Natural Gas Act. Consequently it cannot be guaranteed at this point that FERC will have or exercise authority over the GTP. While there are signs that FERC will regulate the plant—such as the language cited by the Administration to the effect that FERC expects open season rules to apply to the GTP—the question is not yet decided.

The Natural Gas Act also exempts from FERC's authority the "production and gathering" of natural gas. Will the Gas Transmission Pipelines upstream from the GTP be considered "gathering" by the FERC? No one can say with certainty. Historically, the definition of non-jurisdictional "gathering" versus jurisdictional "transmission" has turned on physical and operational factors. In the past, FERC has applied several standards to determine whether particular facilities were gathering or transmission. The FERC has used a "behind the plant" test, a "central point in the field" standard and, most recently a "primary function" standard to determine what was gathering and what was not. Thus, it simply cannot be said that the GTP or the Gas Transmission Pipelines will be subject to FERC jurisdiction.

Accordingly, there may be a question as to whether RCA has jurisdiction over these (or other) facilities or services (such as the impurity disposal service, for example). While the Contract contemplates RCA jurisdiction, it prevents the State from seeking or supporting RCA jurisdiction. This is unacceptable. Absent effective regulation, there is nothing to prevent the Producers from exercising market power to the detriment of other explorer producers. History suggests that the Producer participants will do so. Conoco's Archie Dunham cited his company's woes in Alaska in the early 1990s because the "owners of the pipeline[TAPS], by adjusting the tariffs on the pipeline, could really diminish the value of the producing properties" (Calgary Herald Thursday, August 9, 2001).

The Contract stipulates that the State will indemnify the Producers from losses incurred as a result of RCA orders that do not conform to FERC policies. This begs the question: if FERC fails to assert jurisdiction, how could the RCA regulate in a fashion that is consistent with FERC policies on non-jurisdictional facilities? Since an RCA order requiring refunds would reflect a finding by that Agency that someone has been overcharged, it makes little sense that the State should reimburse the Producers for the loss of overcharges.

Dispute Resolution

As noted previously, all disputes between the State and Participants are resolved by arbitration, including disputes relating to payments and regulatory matters. It should be noted, though, that in committee testimony the parties did acknowledge that the scope of the Contract alternative dispute resolution terms may have inadvertently overlapped with the intended scope of the LLC Agreement's traditional dispute resolution process. The Administration representatives agreed to revisit the language in the Contract to eliminate that overlap and more clearly separate LLC Agreement disputes from Contract disputes. Without review of the LLC Agreement provisions, it cannot be determined whether such overlap will be effectively remedied.

One aspect of the Dispute Resolution Process that is particularly troubling is the lack of penalties or damages. The Contract specifically precludes liability for loss associated with "consequential or incidental damages, including lost profits; or any special or punitive damages." When combined with the general restrictions imposed in the Arbitration provision (especially Baseball Arbitration), this represents a significant shift in risk in favor of the producer Participants.

In the oil and gas industry, the risk of being assessed special, punitive, consequential, and lost profit type damages over and above specific performance and actual damages by a court or Arbitrator represents a significant deterrent toward self serving and negligent behavior that injures another stake holder. Failure to include the power to award such damages amounts to incentive to push the outer limits of the boundaries established in the Contract terms—meant to protect the State's interests—as far as possible.

One of the primary arguments in favor of arbitration is that it saves time and money. No assurance of such benefits has been included in any of the documents presented so far—particularly when one of the parties in the dispute refuses to give an inch. I would point out that the State is currently engaged in arbitration with Exxon Mobil under terms of a royalty settlement agreement entered into by both parties in the early 1990s. The dispute started in 2001. Exxon has vigorously contested the dispute over the destination value and transportation costs used in determining the value for the State's royalty oil. After dragging on the dispute for years and causing substantial expenditures of money to prosecute, the arbitration panel came back with a unanimous decision in favor of the State's position on destination value. The dispute over transportation values continues—even to this day, belying the claim that arbitration saves time and money.

I remain concerned—and opposed—to the deliberate dismantlement of the State's regulatory regime, surrender of the State's sovereign taxing authority, and waiver of the privileges and deference granted to the State in courts. There may be room for the use of such mechanisms for the resolution of disputes between the State and its partners as business partners—but not in the State's role as sovereign.

Ambiguities

There are a handful of ambiguities that the Parties ought to clarify. It is always better to provide clarity in advance to avoid a dispute, than to point fingers later.

Contract Amendments

It is unclear whether Article 39.1 requires Legislative approval for any Contract amendments negotiated after execution. Article 39.1 provides:

> The Parties may amend this Contract only by a written instrument signed by all affected Parties. The affected Parties shall provide Notice of the amendment to all Parties, including a copy of the written instrument.

“Parties” under the Contract means “the State and all Participants.” “State” means the Alaska government, but excluding its judiciary and any independent or quasi-judicial regulatory agency, such as the Regulatory Commission of Alaska or the Alaska Oil and Gas Conservation Commission. The Legislature is not specifically excluded, but legislative counsel has advised that the provision does not require the Legislature to approve an amendment to the Contract. Since fiscal certainty terms can only be granted or revised by the Legislature, clarification is warranted.

Affiliates

A concern has been raised that the definition of “Affiliate” in the Contract may be unintentionally over-inclusive such that it could apply to employees of the companies and even, perhaps, to refineries and filling stations, with the result that Producer employees could be exempted from personal income taxes or sales and use taxes, or Producer refineries and filling stations could be immune from tax increases.

From a review of the Contract definitions and terms (like Article 11.8), it appears that technically, this concern may be substantive. The Contract is replete with provisions providing Participants with tax concessions. By deeming an affiliate to be the Participant under Article 11.8, and by defining Affiliates so broadly, each of these many tax concession provisions could potentially apply to unintended affiliates.

As a solution, a clarifying statement could be added to the Contract explaining the intent of the parties that the tax concessions in the Contract do not apply to such unintended, but technically applicable, affiliates.

Qualified Project Plan

Is the Qualified Project Plan a piece of the contract? In testimony provided by the Administration and Producer representatives, there appeared to be some difference of opinion on this point. With the severity of the Incorporation article of the Contract, the Tribunal will be permitted to examine only the provisions Contract. If the QPP is not a part of the Contract, it is unclear how its contents—and changes to it—will inform the Tribunal if the State seeks to terminate the Contract under Article 5.

Article 8.7 language

In Article 8.7, on State-initiated expansions, some troubling language appears. Article 8.7 provides the following:

> If *FERC* issues a certificate on a basis different than the expansion proposal filed by the *Project Entity*, then the *Project Entity* shall reject the certificate unless any such difference is minor or all the members of the *Project Entity* vote otherwise.

On its face, this means that if the Project Entity filed to implement an expansion and proposed incremental rate treatment (to ensure that existing shippers would not bear a rate increase) the State and the Producers have agreed, in advance, that the Entity is authorized to reject the certificate if FERC approves it but, for example requires rolled-in pricing rather than incremental pricing. Such a requirement would be entirely consistent with FERC's policy regarding this pipeline.

However, this language does not appear to be exclusively attached to State-initiated expansions. This provision could apply to any certificate filed by the Project Entity. This could mean that if the FERC were to evaluate the expansion to ensure that it was adequately sized (or could itself be economically expanded) and were to require a design change (actions it has promised to undertake in the context of the initial pipeline certificate process, and which the Producers have appealed) the State has agreed to the rejection of the certificate.

Further, it could extend to the initial application filed by the Project Entity for the initial construction of the Project. So, even if the Producers lose their appeal on the FERC's authority to order a design change for initial capacity, this provision of Article 8.7 could assure them that they will not be forced to accept any expansion certificate that departs in any meaningful way from the as-filed application. This amounts to yet another potential roadblock to expanding the pipeline and undercuts Article 8.7 as a meaningful tool to assure robust expansion of the system.

Definition of "Loss"

There is a concern with the definition of the term "*Loss*" *vis-à-vis* the provisions of Article 37.2 of the Fiscal Contract addressing Limitation on Damages and Remedies.

The term "*Loss*" is defined in the Contract as:

> ***"Loss"*** means any liability, loss, damages (**including consequential, incidental, lost profits, special, or punitive damages**), demand, claim, settlement payment, cost, expense (including any litigation expense), interest, award, judgment, diminution of value, fine, fee, and penalty, or other charge.

Yet, Article 37.2 of the Contract expressly exempts a party from liability to another party for the following *Loss* damages, which match the bolded language in the definition of *Loss* above:

> **37.2 Limitation on Damages and Remedies.** The *State* and the *Participants* have negotiated this *Contract* in consideration of their consent to limit recovery of certain *Loss*. Accordingly, in no event is any *Party* liable to any other *Party* for the following *Loss*, however caused, that arise out of or relate to this *Contract* or any breach of it:
>
> **(a) any consequential or incidental damages, including lost profits; or**
>
> **(b) any special or punitive damages.**

> A *Party* shall neither claim nor, if awarded, collect any prohibited *Loss* from any other *Party* in any proceeding arising out of or relating to this *Contract* or any breach of it. Except for reformation to correct a minor clerical error, the *Tribunal* shall enforce, but may not amend, the terms of this *Contract*.

The Contract clarification concern arises from that fact that various other articles of the Contract provide for the State to indemnify or reimburse the Producers, or their affiliates and assigns, for *Loss* (*e.g.*, Articles 8.3, 10.10, 11.15, 21.3 and 22.1). These articles should be clarified such that the limitation on damages and remedies in Article 37.2 of the Fiscal Contract apply to these indemnification and reimbursement obligations of the State. It should be clear that the State is not indemnifying or reimbursing anyone for consequential, incidental, lost profits, special, or punitive damages.

IV. Preliminary Findings and Determination of the Commissioner of Revenue

The SGDA requires the Commissioner of the Department of Revenue to reach three preliminary findings at this stage of the process: (1) that the gas is stranded; (2) that the Contract is in the long-term fiscal interest of the State; and (3) that the Contract furthers the purpose of the SGDA. The Commissioner presented his Preliminary Findings and Determination (Finding) on May 10, in which he makes the conclusory findings required by the SGDA. The Commissioner's Finding that ANS gas is "stranded gas" ignores the fact that until now the gas had a higher and better use being reinjected to optimize oil production, and fails to determine that this remains the case. After review of the presentations by the Administration's consultants, the Legislature's consultants, the Producer's representatives, and general public comment, I have reached the conclusion that the data does not support the conclusory findings of the Finding.

ANS Gas is Stranded

> **AS 43.82.900 (13)** "stranded gas" means gas that is not being marketed due to prevailing costs or price conditions as determined by an economic analysis by the commissioner for a particular project.

The Commissioner's Finding that ANS gas is "stranded gas" relies on serious factual errors, incorrect understanding of shipping commitments, and unfounded fears regarding the purported threat posed by LNG. Competition for market share is not part of the definition of "stranded gas". Competition becomes relevant only if it impacts prevailing costs or price conditions preventing gas from being marketed. No such requisite showing was made.

Markets, Price Forecasts, and LNG

The Finding suggests that a competition for market share between ANS gas and LNG imports is a critical test for the economic viability of the Project. The effects each of these sources will have on the market price for natural gas in North America are not simple to predict, but most of the forecasts presented to the Legislature suggest that neither will become the marginal source of supply. Most forecasts[5] also suggest that the market is expecting both sources to be necessary base elements of the total supply make-up to meet increasing demands in the middle of the next decade and beyond. The market does not view these two sources of supply as competing with each other for the same demand, so much as complimenting the demand that each cannot supply on their own. Nonetheless, suggestions by the Administration warrant comment on the differences between the two. Unfortunately, the Findings by the Commissioner rely on a set of erroneous assumptions about the costs of delivering LNG to the United States as well as the cost of getting ANS gas to market.

The Finding identifies transportation costs as one of the most important differences in costs between competing reserves [FIF-C-6]. So, when comparing the differences between LNG and ANS gas, it is critical that such comparisons are done on an apples-to-apples basis and that all costs are included.

The Finding puts the cost of transporting Qatar's LNG at approximately $1.25/mmBtu. While that is the cost for shipping, there are also costs for the liquefaction ($0.80), regasification ($0.40), and access to the pipeline system ($0.10). All told, LNG transportation costs from Qatar to the United States amount to approximately $2.50. Including the other associated costs of production and returns for the exporter, the landed cost of LNG is closer to $3.25. These are current ($2005) market results.

In examining the cost of transporting ANS gas to market, the Finding assumes that the Project will proceed all the way to Chicago. This results in a tariff of approximately $2.20/mmBtu. However, it is unlikely that new pipeline construction will extend much beyond the AECO hub in Alberta and very likely won't go past Gordondale. Rather, ANS gas is more likely to be delivered via takeaway capacity from AECO to the Midwest, West Coast, and East Coast. The rationale offered for assuming a Chicago destination? If the pipeline is constructed to Gordondale, Firm Transportation (FT) commitments will have to be made to move the gas to Chicago. The Finding asserts that purchasing FT commitments is an expenditure that is capitalized. However, capitalization of a future expenditure does not translate such future costs into a current cost of shipping. There is no outflow of cash that occurs when an FT commitment is made and no accelerated cost that would be reflected in a transportation cost analysis. Further, debt-rating agencies don't treat it as an accelerated transportation cost. The Finding offers no evidence to support the assumption that capitalizing FT commitments

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[5] Energy Information Administration, American Gas Foundation, Lukens Energy Group, Cambridge Energy Research Associates, and QatarGas.

to move gas from Alberta to Chicago increases transportation costs as between ANS gas and LNG gas.

Nonetheless, if constructed all the way to Chicago, the toll would be $2.20/mmBtu—in nominal dollars averaged over 40 years. A $2005 average transportation cost is closer to $1.20/mmBtu. Put on an apples-to-apples comparison, no demonstration was made that transportation costs are a barrier to ANS gas reaching the market.

Despite these market analyses, concern was raised that if ANS gas were not promptly brought to market, LNG would overwhelm the North America natural gas market and close the window of opportunity to commercialize ANS gas. Market analyses demonstrated that the North American market anticipates needing significant increased imports of LNG over the next decade and beyond, in addition to the ANS gas. Contrary to LNG closing a window on ANS gas, the market has concerns that ANS gas together with LNG may not be sufficient to meet the anticipated demands for gas. This concern is particularly highlighted by the concern whether sufficient LNG facilities will be constructed to meet the needed LNG supply projections.

According to the Federal Energy Regulatory Commission's website (www.ferc.gov/industries/lng.asp), there are about 40 LNG terminals that are either before the commission or being discussed by the LNG industry.

With passage of the Energy Policy Act of 2005, FERC gained streamlined authority to issue need certificates for LNG facilities. FERC, however, has made it clear in approving need certificates, that it has no jurisdiction over state and local siting approvals. To date, stiff community NIMBY opposition threatens most FERC approved terminal plans. Facilities are subject to an effective "veto" right by the state governments where they are proposed to be located. State governments can block a facility by denying permits associated with the Clean Water Act, the Coastal Zone Management Act, and the Clean Air Act, not to mention local government planning and zoning requirements. Layered onto these LNG obstacles, Homeland Security issues with LNG transport ships and LNG facilities have and will increasingly cause significant delays, if not outright cancellation of proposed LNG facilities. According to the FERC's website, many industry analysts predict that only 12 of the 40 LNG terminals being considered will ever be built.

This reality is beginning to show up in corporate decision-making. Two pipeline projects in excess of 1,300 miles in length are moving forward in an attempt to serve East Coast markets. According to a recent article in the Wall Street Journal[6], neither project would be moving ahead unless the companies involved had grave concerns that new LNG terminals wouldn't be there to supply their gas needs. Conoco Phillips recently executed an option to invest as a 24% partner in one of those projects—the Rockies Express pipeline. BP has a substantial (~200 Mcf/day) shipping commitment on that pipeline. As a result, plans for multiple new East Coast terminals, delivering gas directly to consumers, have largely fallen by the wayside.

[6] Gold, Russel, "Energy Firms Turn to Pipelines, In Bet Gas Ports Won't Happen," Wall Street Journal, June 12, 2006, p.A8.

This is not to say that LNG imports will not increase, as they must to meet the anticipated demand. There is likely to be a proliferation of offshore terminals along the Gulf Coast, which will keep price inflation in the Henry Hub market to a minimum.

However, with the long-term domestic supply of conventional gas on the decline and limited opportunities for LNG imports, the EIA expects the balance of the market to be supplied by steadily increasing unconventional sources. These supplies are currently tight and forecasted to remain so. So long as the cost to deliver ANS gas is lower than the high-cost to deliver unconventional sources of supply, the cost of transporting ANS gas does not appear to be a factor preventing ANS gas from being marketed. This is not to suggest that the opportunity for ANS gas is limitless—only that the FIF conclusion that LNG could displace ANS gas is erroneous. This is not to suggest that the transportation cost could not become a factor.

Project Scale

The Finding also suggests that the scale of the Project—its absolute size—subjects a small firm participating in the Project to a potential risk of catastrophic financial loss of $15 billion at certain low-estimate market prices [FIF-C-9]. This is due largely to the risks of cost overruns associated with large, complex projects. Here, however, the Applicant is not a small firm, but three of the largest companies in the world. The smallest among them has a market cap in excess of $100 billion.

It’s worth noting that the economic risks associated with the sponsor of a pipeline project will be evaluated by the regulatory agencies in the United States and Canada to determine whether to green light the project, and if green lighted, an appropriate rate of return on equity reflecting such risks. These risks include: completion risk, cost overrun, operational performance, capacity gaps, and securing the initial shipping contracts. If the regulators do their job, the allowed rate of return on equity is “adequate” given the project risks. Those returns will be there for the taking so long as shippers are able to make their payments for service on the line.[7]

In reality, neither the project sponsors nor their pipeline subsidiaries will actually invest $18 billion. Most of the capital will come from lenders who are repaid from the revenue generated through shippers’ payments. Plus, the federal loan guarantees available through the Department of Energy combined with the limited recourse financing described in the Fiscal Interest Finding means the Producers’ risk exposure will be hedged on this Project. The combined equity required from all three companies is approximately $4 billion. That exposure can be reduced further if the Producers simply commit to ship the gas on their leases. Such commitment has the added benefit of increasing the performance of their investment metrics as well:

[7] Perhaps that is why two of North America’s largest natural gas transportation companies, MidAmerican and TransCanada, expressed desire to constuct the Project. They went so far as to sign reimbursable agreements with the State of Alaska in order to conduct negotiations of their own to construct and operate the pipeline.

	Upstream		Midstream	
	Contract	ELF-System	Contract	ELF-System
$2005 (M)	$122,273	$118,695	$5,180	$6,745
NPV-10	$22,972	$21,416	($1,744)	($2,214)
NPV-10 per BOE	$2.84	$2.65	($0.22)	($0.27)
Profitability Ratio	14.17	13.52	0.76	0.70
IRR	59.6%	46.0%	6.20%	6.20%

*Assumes $6.00 prices

Nonetheless, if the Producers insist on owning the pipeline, most of the economic projections result in substantial returns—with only extreme worst-case scenarios showing the potential for substantial financial losses. In evaluating the risk to the State, the Administration asserts that "based on its own risk analysis of the effect of a cost overrun, it is determined that even under highly unlikely low gas prices, the State will not suffer a significant impairment of revenue" [FIF 244]. In fact, even if there is a cost overrun of 50% and prices fall into the stress-price range of $4.00/mmBtu, investment metrics (provided by Econ One Research, Inc.) suggest that the cost of the pipeline will not impede marketing of the ANS gas:

	Proposed Contract	ELF-Based System
$2005 (M)	$69,672	$66,957
NPV-10	$7,971	$5,332
NPV-10 per BOE	$0.99	$0.66
Profitability Ratio	1.67	1.37
IRR	15.90%	13.20%

Competition Among Projects Worldwide and Rate of Return

The Finding relies entirely on the portfolio database compiled by PFC to determine whether or not the Project is sufficiently attractive to warrant investment by the Producers. However, the PFC comparison made here contains serious factual and conceptual problems.

For the other projects identified in the portfolios, the investment metrics do not include the full range of investment costs. For instance, LNG project costs do not include capital outlays for tankers, regasification facilities and pipeline access costs. There were two immediately obvious incorrect "comparable" projects: Kashagan and Agbami. PFC has Kashagan as the highest of the peer group at around 40% IRR at a $35/BBL oil price. According to Daniel Johnston, who has recent professional experience working for the government of Kazakhstan on this project, it should be less than 15% at that price if done correctly. Agbami (offshore Nigeria) should be more like 13%, according to comments made by Conoco-Phillips' chief economist Marianne Kah. These flaws prevent a fair apples-to-apples comparison.

With regard to the Alaska Project, the calculated metrics do not reflect actual cash flows. While the midstream cash flows will largely be debt instruments governed by regulators at the FERC and NEB, the upstream cash flows (at least at Prudhoe Bay) will not begin until the Project is in commercial operation. The upstream shipper will pay tolls but at the same time realize sales revenues. This mistake may be caused by the continued misapplication of FT commitments as capitalized debt-like recordings on corporate balance sheets. Again, capitalizing FT commitments does not accelerate their cost impact for comparison purposes.

Even if one were to assume that the PFC database is correct on all accounts, relying on the Internal Rate of Return to evaluate projects is an inappropriate measure to rank projects in a capital constrained portfolio. Dr. Anthony Finizza demonstrated this in his June 14, 2006 presentation to the Legislative Budget and Audit Committee. You can find his full presentation on the Committee's website (http://lba.legis.state.ak.us). Further, aside from the analysis of PFC comparables, the Administration has never articulated what the proper IRR should be.

Finally, the evaluation fails to consider the continually acknowledged fact that the Project is the largest single source of reserves that these companies can book for the benefit of their corporate shareholders. These reserves can only be booked upon construction of the pipeline. Investing in other pipeline projects around the world does not provide the economic benefit to the companies from booking the Alaskan gas reserves. The Alaska Project also happens to have the best financial performance of any of the competing projects at forecasted prices and costs of construction (on NPV-10 basis). Again, the Finding does not meet the definition of "stranded gas" required by the SGDA.

Contract is in the long-term interest of the State

The Commissioner identified the following aspects of the Contract as examples of why it is in the long-term interest of the State of Alaska.

Generation of Additional Revenue is the Goal of the Contract

A share of the Project revenues will only accrue to the State if the Project moves forward. It is clear—and agreed by all parties—that there is no affirmative commitment to actually build the pipeline contained in the Contract or to commit to ship the "stranded" gas on the pipeline if constructed. Without such commitments, the Contract benefits may be an illusion at best.

Government Share of the Project Revenues is Fair

Total government take for this contract is around 51%. According to information provided by Daniel Johnston in his June 15, 2006 report to the Legislative Budget and Audit Committee, this is commensurate with the average take figures for LNG projects proposed around the world. However, there are three factors that warrant further consideration.

First, the State's share of the take is 21.2% at a base case price of $6.00/mmBtu. Meanwhile, the federal government's share is approximately 28.8% at the same prices. Without quantifying all of the benefits afforded the Project by the federal government and comparing them to the benefits afforded the Project by the State through the Contract, one thing is certain: the federal government is in no way providing benefits and certainty of a like degree, caliber, or scale as the State.

Second, as mentioned previously, the risks and obligations proposed in the Contract represent a significant departure from existing oil and gas policy as it has existed in the State since 1959. Commensurate with the State assuming those additional risks should be a greater share of the upside potential. The Contract fails to deliver that upside.

Third, the State is contributing far more than 20% of the costs through deductions, credits, and allowances for its approximately 20% share of the revenues. This is particularly true on the upstream elements of the project. While the State will share in the operating expenses of upstream activities through a 20% deduction against oil taxes, it will be sharing a disproportionate share of the burden on capital expenditures through the 20% deduction plus an additional 20% credit. On some of the Midstream Elements (GTP, Transmission Lines) that do not qualify as lease expenditures for deductions and credits against oil taxes, the State will contribute its share of the capital plus an additional 35% credit.

The Period of Stability granted is reasonable

The Findings conclude that complete elimination of the State's share of Project revenues would do little to improve Project economics. As previously stated, and for the reasons previously stated, the Term of the Contract has no factual support and is not reasonable.

The Contract has a Neutral Effect on State Revenues

While the severance tax rates appear to be neutral and pipeline ownership generates positive net revenues for the State, the costs, deductions, and allowances awarded in the Contract result in a net reduction in State revenue as compared to the current fiscal system[8].

[8] There are two additional issues that have not been quantified at all: there has been no attempt to quantify the investments (and subsequent deductions and credits) that will be necessary at the aging PBU facilities to support oil and gas production for the life of the Project or the Term of the Contract; there is no examination of the costs of suppressing the State's regulatory regime as it applies to oil and gas properties subject to the Contract.

	Estimated Project Revenues to State and Munis (Base $6.00 Case)	State Metrics		
		Proposed Contract	ELF-Based System	Difference
			(Million $2005)	
1	Gas Revenues (Royalties and Sev. Taxes)	$ 36,904	$ 42,651	$(5,747.00)
2	Property / Income Taxes	$ 9,773	$ 11,097	$(1,324.00)
3	GTP / Feeder Credits	$ (896)	$ -	$ (896.00)
4	Revenue Before Oil Effects	$ 45,781	$ 53,748	$(7,967.00)
5	Oil Effects	$ 5,822	$ 3,987	$ 1,835.00
6	Revenues Before P/L Investment Income	$ 51,603	$ 57,735	$(6,132.00)
7	P/L Investment Income	$ 1,230	$ -	$ 1,230.00
8	Total Revenues After P/L Investment	$ 52,833	$ 57,735	$(4,902.00)

The above table differs substantially from the tally published by the Department of Revenue in two important ways. The first is on the treatment of deductions and credits at the Pt. Thomson Unit. For purposes of looking at project economics, the Administration allocates 100% of the capital development and operating costs to gas, recognizing that development of the field is necessary to the Project. However, when looking at what happens to severance tax revenue, the Administration allocates 100% of those same development and operating costs to oil, effectively double counting the cost allocation.

The problem with the Administration’s approach on this can be illustrated in the following: if the Administration’s mid-price forecast of $5.50/mcf and $36/bbl for oil is used, Econ One Research’s analysis indicates that allocating all costs to oil results in an effective severance tax rate of less than 7%. Moreover, because the deductions that come with the PPT system will come during the early development years of the field, the effective tax rate on the present value (PV-8) of those revenues will be less than 3%. These rates can be compared to the Administration’s projected tax rates under the ELF system, which would be 12.5% in the first five years and 15% thereafter.

This is problematic on two fronts. First, the operators are currently arguing before two state agencies (AOGCC and DNR) that the PTU is a gas field. It is difficult to see the logic in allocating costs to the substance that would be considered a secondary product of the field. Second, the resulting effective tax rate on oil provides some validation to the criticism that the Contract gives away Pt. Thomson.

The second difference in the table is the inclusion of the 35% contribution credit that the Contract calls for on GTP and Transmission Line investments. Econ One Research includes it in their analysis of expected revenues associated with the Project. The Administration, however, allocates 100% of it to oil. These are facilities that will only be constructed if the Project moves forward. Again, it is difficult to see the logic in this approach.

In order to make concessions of this magnitude economically beneficial to the State, Project acceleration of at least 5 years is necessary. Nowhere in the Contract is it contemplated that the concessions clear this hurdle.

The State is Acting Reasonably to Anticipate National and International Political Action Affecting the Project

The Contract's commitments to joint ownership in Canada between the State and its Producer partners and the solicitation of exclusive NEB jurisdiction is likely to lead to disputes that would trigger delays to the Project schedule embodied in the QPP. Indeed, press accounts last week from Canada suggest that a dispute is highly likely[9].

The Administration's finding that the State is acting reasonably to anticipate international political action is stale and flawed in major respects. The Administration has endeavored to reduce Alaska's government take in order to make the investment climate in Alaska competitive with other nations having gas resources not currently being marketed. The assumption that Alaska must reduce its take to compete appears to be based on stale data. Elsewhere in the world today governments are demanding increases in government take in response to the perceived windfall that the investors are reaping as a result of higher prices, especially for existing reserves. In addition the Administration has compared the fiscal and commercial terms of other countries but has failed to take into account the full spectrum of the investment environment in these other countries.

The Administration cited Angola, Azerbaijan, Nigeria, Kazakhstan, Qatar, and Russia as examples of jurisdictions with which Alaska must compete for foreign investment. The underlying premise of the Administration's comparison ignores the qualitative differences in the investment environment in terms of corruption, political risk, economic risk and transparency of the legislative and regulatory processes and assumes that the investment environment of Angola, Azerbaijan, Nigeria, Kazakhstan, Qatar, and Russia are analogous to the investment environment of Alaska. When the premise of a comparison is faulty, then the comparison is inappropriate and misleading.

Transparency International annually ranks countries on a corruption perceptions index. The higher the numerical ranking the more corrupt the country is perceived to be. In 2005 TI ranked 158 countries (http://ww1.trasnparency.org/cpi/2005/2005.10.18.cpi.en.html): Canada is (14), Norway is (8), UK is (11), US is (17), Angola is (151), Azerbaijan is (137), Nigeria is (152) , Kazakhstan is (107), Qatar is (32), and Russia is (126). Political Risk Services provides analyses, rankings and forecasts of political, economic, and financial risks for 140 countries. The political risk is a proportion of one hundred where 0-49 is very high risk, 50-59 is high risk, 60-69 is moderate risk, 70-79 is low risk and 80-100 is very low risk (http: www.prsgroup.com/icrg/sampletable.html): Canada is very low risk (86), Norway is very low risk (88), UK is very low risk (84), US is very low risk (82), Angola is high risk (58), Azerbaijan is moderate risk (64), Nigeria is very high risk (42), Kazakhstan is low risk (70), Qatar is low risk (73), and Russia is moderate risk (66).

[9] "Alcan pipeline dispute heats up," CBC News, July 21, 2006

Angola, Azerbaijan, Nigeria, Kazakhstan, Qatar, and Russia have a nominal democratic process but in fact are each run by strongmen with legislative and regulatory processes that are not readily understandable by or open to participation by investors. By comparison Alaska is significantly more transparent, significantly more politically and economically stable, and has legislative and regulatory processes that are understandable and open to participation by investors. Corruption, political and economic risk and opaque legislative and regulatory processes are key reasons why Angola, Azerbaijan, Nigeria, Kazakhstan, Qatar, and Russia need to offer stabilization even in connection with an economically attractive investment.

The Contract Furthers the Purposes of the SGDA

There are three specific purposes laid out in the SGDA.

> **AS 43.82.010. Purpose.** The purpose of this chapter is to
> (1) encourage new investment to develop the state's stranded gas resources by authorizing establishment of fiscal terms related to that new investment without significantly altering tax and royalty methodologies and rates on existing oil and gas infrastructure and production;
> (2) allow the fiscal terms applicable to a qualified sponsor or the members of a qualified sponsor group, with respect to a qualified project, to be tailored to the particular economic conditions of the project and to establish those fiscal terms in advance with as much certainty as the Constitution of the State of Alaska allows; and
> (3) maximize the benefit to the people of the state of the development of the state's stranded gas resources.

Encourage New Investment without significantly altering tax and royalty methodologies

The overarching problem with the contract is that it is not an agreement to develop the gas resources of Alaska from the properties contained in Exhibit D. Rather, it is an agreement to study development, with no commitments to construct a pipeline or commit to ship gas on the pipeline. In effect, the proposed contract is an open-ended option agreement, giving the Producers current economic benefits whether a pipeline is built or not (*e.g.*, waiver/deferral of current lease obligations), and future benefits if they elect in the future to construct the pipeline. Unlike other option contracts, the Producers provide no *quid pro quo* to the State for issuance of the option. Worse, this option has no time limits or performance standards for completion of a pipeline, while effectively precluding the State from seeking specific performance against the Producers, or seeking alternative means to construct a pipeline if progress is not being made. To that extent, this contract is an inefficient means for promoting development.

While, aside from including oil taxes in the Contract, the tax and royalty methodologies are not significantly altered, the credits, deductions, and cost allowances authorized by the Contract amount to concessions that have the effect of reducing revenue collection by the State.

Tailored to the particular economic conditions of the Project and to establish those fiscal terms in advance with as Much Certainty on Fiscal Terms as the Constitution Allows

The SGDA contemplates setting “fiscal terms” yet fails to define what constitutes a fiscal term. The Contract interprets “fiscal terms” very broadly—the entire oil and gas regulatory regime in Alaska is redefined or made subservient to the Contract. In that respect it is overly broad and contrary to the intent of the Legislature in adopting this SGDA standard.

The one condition needed to advance the Project is the commitment of Prudhoe Bay and Pt. Thomson reserves to shipment on the pipeline. As a function of upstream economics, the economic condition to be treated is the price risk for upstream shippers (or sellers). To that end, the Contract should aim to keep costs down and netbacks high.

Maximizes the Benefits to Alaskans

In the third test of the SGDA, the word “maximize” connotes something more than the old adage, “something’s better than nothing.” The Producers, under their leases with the State, have already undertaken the obligation to develop the gas resources[10]. Given that, Alaska should not have to give up more than is necessary to get the pipeline built. This is not a question of who gets what, but who gives up what. The provisions for Alaska Hire and Alaska Buy simply do not get the job done. While a boom will certainly benefit Alaska workers, companies, and the economy, we should not settle for a single boom. Rather, we should be looking for a thirty-year boom that includes exploration and development of Alaska’s gas prone areas as well as regular expansions of the line to accommodate more gas and provide more opportunities for in-state use. To that end, the Contract should ensure that expansions will happen—early, often, and in increments sized to deliver expected reserve discoveries.

Summary

In summary, the reason ANS gas has not been developed is because no party has yet constructed the transportation infrastructure necessary to deliver the ANS gas to market. At the time the SGDA was enacted, the market dynamics were significantly different than they are today. The ANS gas has not been brought to market principally because until now its higher and better use has been to be reinjected to optimize oil production. That appears to be no longer true. Demand for gas has increased significantly. Domestic supplies of gas have diminished and will continue to diminish. Due to short supply, greater demand, and external influences (Gulf Coast hurricanes, Middle East unrest), the price of gas has significantly increased, as has the price of oil. LNG imports continue to face serious environmental and national security concerns. In addition, Congress has adopted a streamlined/expedited permitting process and Federal financing guarantees to

[10] See the memorandum prepared by the firm Hosie, McArthur dated June 1, 2005.

assist in the development of an Alaska gas pipeline. These changes make the construction of a pipeline more economically viable today than at any time in the past.

At the same time, the cost of pipeline construction has increased, a factor that supports the development of a Contract that fairly allocates that risk and provides appropriate sticks and carrots to get the pipeline built. The Findings, however, do not properly address the requirements of the SGDA, as they suffer from serious factual errors, incorrect treatment of shipping commitments, and misplaced fears regarding the threat posed by LNG. The Producers need only to commit the gas reserves that they control through State leases to a pipeline project and commit to construct the pipeline. The fact that the Contract deals primarily with upstream—rather than midstream—issues underscores the point that the Contract does not provide the *quid pro quo* anticipated by the adoption of the SGDA.

V. Recommendations

With the above comments in mind, the following recommendations would make the Contract more consistent with the goals and purpose of the Stranded Gas Development Act—namely, to receive commitments that will lead to development of stranded gas. These recommendations are general in nature, though, and do not reflect all of the corresponding changes to definitions and interrelated elements of the Contract necessary to fully implement the improvements.

Work Commitments

To create more definitive "work commitments" consistent with the goals of the SGDA, the Contract must:

- set out in the body of the document the specific activities and the timeline to be performed in order to obtain the information necessary to decide whether to make a commitment to build a gas pipeline. An example might be incorporation of the QPP as an exhibit to the Contract, with the full description of activities and time projections established as commitments of the Participants;
- provide in the body of the document that specific milestones must be done by specified completion dates. An example might be the requirement to submit certain regulatory applications by the second anniversary of effective date, and to declare Project Sanction by the fourth anniversary of effective date;
- provide in the body of the document that the specific activities and the timeline comprising the "work commitment", and the milestones and corresponding completion dates, may not be changed without the consent of the Commissioners of Revenue and Natural Resources; and
- provide in the body of the document that if a milestone is not achieved by its corresponding completion date, the fiscal contract will terminate, unless the State in the exercise of its judgment consents to change the work milestone, or the specified completion date; and provide the State the right to seek damages or specific performance of the milestone as an additional remedy.

Without strengthened work commitments, the State must enjoy the right to terminate the Contract up until Project Sanction has been declared.

Diligence Standard

Regardless of whether work commitments are strengthened, the “Diligence” standard established in Article 5 must be modified.

Adoption of an alternative standard that is more commonly used in the oil and gas industry, coupled with continued reliance on a judicial system that is bound by existing precedents in adjudicating those standards would provide greater protection and predictability for the State. That standard should be the Prudent Operator Standard.

The Prudent Operator Standard governs the performance of implied covenants in oil and gas leases and applies currently to the leases at issue in the Contract. The standard would obligate the Participants, in developing the pipeline, to do what would reasonably be expected by another operator similarly situated of ordinary prudence, having regard to the interests of all parties.

Qualified Project Plan

Inasmuch as the State, through the Contract, is making material and long-term tax and royalty concessions to the Producers and these concessions will become effective when the Contract is signed rather than when the project is completed, prudence dictates that the State should have some assurance that it is getting the type of effort and results it expects from the Contract.

The Contract should require that the Commissioners of Revenue and Natural Resources have approval authority over material changes to the Project Plan. The Administration suggests that it would be difficult to negotiate what constitutes a “material” change. This argument makes some sense, and can be easily remedied by listing the particular critical State issues that would require the State Entity’s consent. They would include timing and scheduling changes, and any significant capacity changes.

Expansions

One of the main concerns about the Contract is the lack of any affirmative commitments regarding the terms or conditions under which a voluntary expansion could be undertaken by the Project Entity. The concern here is that some or all of the Producers may have rational reasons as producer/shippers to resist voluntary expansions. It is clear that the State has interests in having the line expanded that differ from, and may even be adverse to the interests of the Producers as producer/shippers. Thus, the Contract should contain binding commitments as to expansion terms and conditions.

It is reasonable for the State to establish as part of the Contract the terms and conditions under which the Project Entity LLC will undertake voluntary expansions, including:

(1) holding periodic (3-5 years) binding or non-binding open seasons to assess market demand for expansion;
(2) commit to satisfy all creditworthy demands for capacity expansion in reasonable engineering increments;
(3) commit expansion for creditworthy shippers in less-than reasonable engineering increments when such shippers commit to contributions in aid of construction sufficient to keep the project entity whole, including authorized return; and
(4) commit the Project Entity to propose and defend the use of rolled-in pricing for all expansions.

Regulatory Commission of Alaska Jurisdiction

Absent FERC regulation of all elements of the Project, nothing will prevent the Producers from extracting monopoly rents or exerting monopoly power over access to facilities. Article 8.3 prevents the State from taking steps that would prevent such action on the part of its partners—which would have a chilling effect on the exploration and development of Alaska's vast natural gas resources. The State should not allow its ownership interest in the Project to undermine the constitutional mandate to promote the development of its resources. Article 8.3 should be repealed in its entirety and the Contract should affirmatively assert RCA jurisdiction over elements of the Project where FERC fails to assert jurisdiction.

Article 8

As mentioned above, suppression of the State's regulatory regime via the Regulatory Commission of Alaska should not be a term of the Contract. In addition, the State has no business in demanding that Canada regulate this project in a particular manner, much less agreeing to a specific regulatory body when alternatives exist under Canadian law. As such, Articles 8.1, 8.2, and 8.3 should be deleted entirely.

Article 8.6 does nothing to reduce the cost of service. In fact, it creates an opportunity for the Producers to argue for a substantial write-up in the value of all previously used assets that are converted to gas pipeline service. Due to the potential impact on cost of service rates at the GTP, Article 8.6 should be revised to require the use of net book value for previously used assets. If that is not possible, then the section should be deleted entirely.

Article 8.7 contains so many conditions that it provides little reason to expect that it will result in an expansion. It should be deleted and replaced with a sole risk expansion provision.

Sole Risk Expansions

State investment in expanding the line at its sole cost and risk represents one way of satisfying the State's unique interest in expansion while requiring no investment by the other project sponsors.

There is precedent for each party in jointly owned pipelines (or pipeline segments) to have the right to expand the system at its own expense and risk. This is sometimes referred to as a "sole risk" provision. One example of such a provision is contained in the ownership agreement between Maritimes & Northeast Pipeline LLC and Portland Natural Gas Transmission System. There, the two companies agreed that each should at all times have the right to expand the joint facilities if, after giving notice to the other party, the two did not agree to jointly expand the line. In such event the ownership share of the party expanding the facilities would be increased to reflect the new investment. By this means either party was free to meet its own, unique requirements even when its co-owner had no reason to invest in an expansion of the jointly owned facilities.

A sole-risk expansion addresses the issue of capacity only. It does not dictate how the expansion capacity would be priced. Presumably, though, if the State had the right to pursue such an expansion under the Contract it would have the right to advocate for expansion capacity to be priced on a rolled-in basis even if the sponsors retained the right to oppose such pricing.

Capacity Management

The capacity management provisions of Article 10 go a long way towards protecting the State's interests that are a product of taking all royalties and severance taxes in-kind. However, Article 10.8 terminates these provisions if the State undertakes to release any of its capacity. It is so critical, in fact, that in the event FERC fails to approve Article 10 in its entirety, or the NEB, Department of Justice or any court finds it to be in violation of *Law*, the State should enjoy the option to terminate the Contract.

In addition, a change to Article 10 could help address the challenge of providing State Gas to in-state destinations as infrastructure demands increase. The Article should be modified to allow the State to provide notice to its Producer partners at each open season to increase its In-State Gas volumes by releasing firm capacity downstream from an in-state offtake point. The result would be a decrease in the State's export gas volumes. In this way, the State could increase deliverability of gas to satisfy in-state demands as infrastructure develops to make use of the gas.

Term

The Administration's findings as to why certainty on oil is necessary fail to make a convincing argument. There is no other place in the world that has granted such "retroactive" stability on existing production. Terms relating to oil should be stripped from the Contract entirely. Based on the economic models presented to the Legislature, the term on stability for gas should be shortened to no more than 5 to 15 years after the pipeline is operational.

Price Differential Payment

As stated previously, the State, through this Contract, is taking on unprecedented risks. This is a product of the Producers wishing to reduce project risks. These companies look at risk asymmetrically. That is, if things are equally likely to go better or worse than is expected, then they are more concerned about the downside than they are attracted by the upside. If the State is going to take on these downside risks, then it should share in the upside rewards.

In October 2004, the DNR proposed to the gas cabinet a mechanism to do just that. The Price Differential Payment would involve payments either from or to the State based on the price of gas in Chicago. In his memo dated October 27, 2004 Dr. Pedro van Meurs opined that such a payment system would improve the economics at stress prices and help create a true sharing of the price risk since the State would get very significant additional rewards at higher-than-expected prices. The formula proposed then would have made up for the loss of the State's "higher of" provisions in its competitive oil and gas leases once the price of natural gas in Chicago reached $5.00 per MMBtu.

Most importantly, though, he also stated in that memo that including such a provision is very important because he had concerns that the upside under the deal is too good for the producers—which would undermine the stability of the deal. The SGDA calls for the consideration of a wide range of economic circumstances as well as a progressive share of the economic rent of the project [AS 43.82.210(b)(2) and (3)].

The Contract should be amended to include a Price Differential Payment similar to that proposed in the State's initial contract proposal in October 2004.

Suppression of the State's regulatory regime

Article 41.2 is disturbing and alarming. Because the Contract is so broad in its scope and specifically refers to so many entities, leases, properties, assets, and types of activities, the impact of this "conforming" provision on the State's regulatory regime would be very far-reaching and will probably have many unintended consequences. Thus, this section should be deleted.

If Article 41.2 is to remain in the Contract, it should be amended to include a Prudent Operator Standard governing the performance of duties in leases and unit agreements. The standard would obligate the lessee, in developing and protecting the leased premises, to do what would reasonably be expected by another operator similarly situated of ordinary prudence, having regard to the interests of both the lessor and lessee with a reasonable expectation of profit.

Modify the Take Point

There is an alternative in-kind taking scenario that would be responsive to what was originally identified by the Participants as their principal concern, that being that they have greater certainty over the timing of the State's commitments to in-kind or in-value taking. The point of in-kind taking could simply be shifted from its currently proposed locations—as far upstream as possible—to a point downstream as far as possible. This could be as far downstream as the AECO Hub in Alberta. Volumes of State gas destined for any of the four off-take points in Alaska could be taken at the outlet of those off-take points.

The State would still be responsible for paying for the transportation of its share of costs in moving its gas to Alberta. It would not, however, have the increased risk and exposure that flows from the capacity management responsibilities of the current proposal, nor would it need an expanded bureaucracy and a host of consultants through the term of the Contract to manage the capacity of its royalty and tax gas sales.

Exhibit D and Supply Commitments

Exhibit D should be limited to those properties that will supply gas for the initial capacity on the gas pipeline. The current list is exhaustive and, when combined with the provisions of Article 41.2, would remove the State of Alaska as a regulator and sovereign.

Those properties that will supply gas should do so through explicit and binding commitments of reserves, volumes, and deliverability. The State can be flexible in allowing the Producer to identify those properties at the same time it provides notice to the State in Article 10.7.

Disputes, Arbitration, and Choice of Venue

The breadth of Article 26.1's coverage of disputes combined with the provision in Exhibit C.8(b) leaves no question that all disputes, even administrative and regulatory disputes, would be resolved by arbitration. This is unacceptable. However, if the State is to enter into a business partnership with the Producers, it is unreasonable—as a matter of doing business—to refuse to waive sovereign immunity as a defense in disputes between partners.

The term "dispute" should be limited to: a dispute, matter, controversy or claim arising out of or relating to any owner entity of the project, to any ownership interest in the project, to any agreement between or among the members or owners of any owner entity of the project arising out of or relating to such owner entity of the project, or to the operation, management, or implementation of the project, including its interpretation, construction, performance, enforcement, privileges, rights or obligations.

As acknowledged by the participants in roundtable discussions, the parties did acknowledge that the scope of the Contract alternative dispute resolution terms may have inadvertently overlapped with the intended scope of the LLC Agreement's traditional dispute resolution process. The Contract must address this overlap.

The parties also acknowledged that venue and choice of law are independent contractual issues, such that parties to a contract can agree to a dispute resolution venue different from the location of the parties' principal place of business or the location of the state of incorporation of the entity. It is common practice for a court in one state to apply the law of another jurisdiction to resolve disputes.

The question of venue for dispute resolution generally focuses on a few key policy considerations: nexus of the subject matter of the dispute to the judicial forum; convenience of the forum to parties and witnesses; and competence of the judicial referee to address the technical issues involved in the dispute. The Contract resolved these considerations in favor of Alaska. The LLC agreement should do so as well.

LLC, Coordination Agreements

The Contract should be amended to include template LLC Entity Agreements and Coordination Agreements as exhibits attached to and made part of it. The Participants should be required to utilize the templates without material modification for implementation of the Project. The Contract should not be transmitted to the Legislature for ratification and execution until all documents reasonably related to the ownership, governance, management and control of the State's participation are submitted for review.

If the Contract is going to be transmitted without these documents, then it should allow the Legislature to authorize termination of the Contract until the terms and conditions of all documents reasonably related to the ownership, governance, management and control of the State's participation have been approved by the Legislature and are executed.