11982 SENATE RESOURCES

STATE OF ALASKA

DEPARTMENT OF REVENUE

OFFICE OF THE COMMISSIONER

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August 1, 2006

The Honorable Edward S. Itta
Mayor of the North Slope Borough
P.O. Box 69
Barrow, Alaska 99723

Dear Mayor Itta:

We would like to thank you for your hospitality at the Alaska Gas Pipeline public forum in Barrow and for your comments.

This letter contains the state's reply to your points raised in your July 24, 2006 comment submission on the Stranded Gas Development Act Contract and Preliminary Fiscal Interest Finding. We would welcome any additional thoughts on these issues you may have.

Sincerely yours,

William A. Corbus

William A. Corbus
Commissioner of Revenue

Responses to Mayor Edward S. Itta's July 24, 2006 Comments

Mayor Itta has articulated important issues in his July 24 Comments. The contract, developed by the State as authorized under the Stranded Gas Development Act, was the result of give and take negotiations and as such was a compromise with the Producers to get a pipeline. In reviewing the State's response the Mayor's Comments, the reader should bear in mind the risk that the pipeline does not go forward at all, current declining North Slope oil production and the prospect of declining revenues to the North Slope Borough. The proposed contract will bring a pipeline and provide the fiscal certainty on oil that is necessary to stem the decline in oil production, the combination that will insure the North Slope Borough an increased and steady long term revenue source.

1. The "Targeted Tax" definition is problematic

Both the sponsor group and the Municipalities acknowledged early on in the process the need to protect the project against targeted taxes. The state was also aware that the use of the 20 percent threshold as a measure of targeted taxes could create a situation where an otherwise typical tax might be classified as targeted. To eliminate the financial risk on the Municipalities while still giving fiscal certainty to the sponsor group, the state agreed in the contract to require that these taxes be paid to the municipalities regardless of whether they are targeted or not. The local taxing jurisdictions are kept whole, and can make sure they are kept whole under their own ordinances, boards of equalization and other democratic institutions. Then under the contract, if those payments have exceeded certain amounts or other tests, the state will reimburse the taxpayer. Under this contract provision the North Slope Borough will be able to recover the revenue from the EIAP, but it will require the implementation of a sales and use tax to do so.

2. Local education funding is reduced by the Contract

We agree with your analysis of the school funding issue, and it was never our intent to diminish the school funding mechanisms. Thus as the outlines of the contract became clear, we requested (and both the bodies of the legislature accepted) language to make

sure the assets which though tax free had associated PILTs, would remain in the tax base at full and true value. While this bill did not pass out of the legislature in the first special session, we encourage you to support this bill when it comes up in the next special session.

3. The Contract may affect municipal bond ratios and ratings

When this issue was first brought to the state's attention it checked with its bond council to determine the effect of switching from a tax structure to a PILT structure. We believe that if revenue streams are sufficient to carry the bonds that the switch to a PILT would probably have little effect on the bonds. The greater problem appears to be that by limiting the payment to the Municipalities to 100% of the PILT, the contract has removed the assurance of an unlimited taxing authority. Under current law there is 30 mill cap for operating funds in law and no limit on taxes to repay debt. Although, for all practical purposes there appears to be an effective informal 20 mill cap, the state understands the North Slope Borough's concerns over their bond solvency but believes, based on its review with its bond council, that the North Slope Borough's concerns, although warranted, are sufficiently addressed in the contract.

4. The Borough unfairly loses revenues due to valuation and NPV calculations

The North Slope Borough is correct in pointing out that the contract does not replace all traditional tax payments with PILTs of an equivalent Net Present Value. This issue will be addressed in more detail as it relates to specific comments of the NSB. You are also correct in pointing out that under the current contract they potentially stand alone as the only local government that will sacrifice revenues during the operation of the pipeline. However the North Slope Borough is not alone in the reduction in revenues during construction of the pipeline.

Although there is no specific language in the Stranded Gas Development Act that dictates the level of payments to Municipalities, the State in negotiating the contract

language as it relates to Municipal revenues attempted to maintain an income stream of equivalent NPV during the life of the contract. In order [to] determine whether the contract language met that goal, it is necessary to look at the entire PILT revenue stream rather than individual PILTs in determining the equivalency of the payments.

It is clear that the calculation of the NPV equivalency is directly related to the assumptions used in determining inflation rates, production rates, and discount rates and as such is open to debate. However, it is reasonable to estimate that the contract, assuming a 4.5 bcf pipeline, will make available, to the North Slope Borough, an additional $80,000,000 in annual gas related revenues once the pipeline is completed. In addition, the PILT structure for the oil related assets generates as much as $1.5 billion in additional revenue over and above the status quo tax structure during the life of the contract.

5. The Contract methodology undervalues North Slope Borough properties, and the Gas Treatment Plant is undervalued by the Contract

The North Slope Borough is correct in pointing out that the contract does not replace the traditional tax payments that would be associated with the GTP with PILTs of an equivalent Net Present Value. However, in order to determine the sufficiency of the payments under the PILT structure in the contract it is necessary to look at the entire PILT revenue stream rather than individual PILTs in determining the equivalency of the payments.

It is clear that the calculation of the NPV equivalency is directly related to the assumptions used in determining inflation rates, production rates, and discount rates and as such is open to debate. However, it is reasonable to estimate that the contract, assuming a 4.5 bcf pipeline, will make available to the North Slope Borough an additional $80,000,000 in annual gas related revenues once the pipeline is completed.

6. The Oil Properties provisions in the Contract undervalue TAPS in the Borough

The cash flow from the PILT on TAPS in the contract translates into a value for TAPS higher than any value seen since 1995 – 3.5 billion dollars. None-the-less, it does not represent the 2006 value of $4.3 billion which is found in the State Assessment Review Board decision. (Under appeal by the owners in Superior Court) Our modeling, which State Petroleum Property Assessor, Randy Hoffbeck, has shared with you, shows that some years out, the inflation and throughput driven calculation based on a 2006 value of $3.5 billion results in higher cash flows to the taxing jurisdictions than the traditional inflation and depreciation driven calculation based on $4.3 billion in 2006.

7. The Oil Unit of Production method of assessment must have a logical and defensible tie to the capital assets

The use of a volumetric measure of value was proposed by the state in 2002 and had been in a test mode for the tax years 2003 - 2005. The contract language adopted the methodology and included escalators starting in the 2007 tax year. In addition, to help in the transition to a PILT structure, the contract allowed for the use of a five year average production in the 2006 and 2007 tax years. Based on the current production forecasts it appears that this will result in a cumulative loss in potential revenue to the North Slope Borough of $22,000,000 through 2010. However, after 2010 it results in revenues in excess of status quo. During the life of the contract that additional revenue could equate to as much as $1.5 billion dollars.

In switching to a PILT system the state acknowledges that the use of a volumetric approach as structured in the contract will not equate directly to full and true value under the current tax system. It is also clear that this will result in revenue shortfalls in the near term to the North Slope Borough. However the long term benefits of the volumetric PILT appear to far offset the short term losses.

8. The inflation and depreciation calculations in the Unit of Production methodology for oil undervalue the assets

In switching to a PILT system the state acknowledges that the use of a volumetric approach as structured in the contract will not equate directly to full and true value under the current tax system. However the long term benefits of the volumetric PILT appear to far offset the short term losses.

9. The Oil Unit of Production method of assessment does not protect municipalities from large revenue fluctuations

Revenue fluctuations have been a part of the assessment of ANS assets long before a volumetric approach was implemented. In fact the use of a volumetric approach has eliminated the use of redesign studies by the taxpayers as a tool in controlling their tax liabilities. In the past these studies resulted in large adjustments to the assessed values by as much as 10% in a single year. The studies were initiated by the tax payer at an ever increasing rate during the late 90's and early 2000's and were impossible to forecast and difficult to defend against. The use of a volumetric approach has allowed for much more accurate assessment forecasts on an annual basis.

Although the proposed PILT structure does not provide downside protection on revenues, it is true to say that the current tax system did not offer protection either. In addition, the current PILT has no upside limit and will respond quickly and significantly [with] increase[d] revenues if new production is brought on line.

10. The Unit of Production methodology for oil must be subject to periodic review

The state agrees that the "per barrel rate" cannot remain fixed and must adjust over time. Rather than provide for reopeners that would result in fiscal uncertainty to both the producers and the North Slope Borough the state included annual inflation adjustments within the contract. A review of the cash flows from the PILT indicates that the inflation adjustment is sufficient to account for changing costs anticipated during the life of the contract.

11. The Gas Unit of Production method of assessment must have a logical and defensible tie to the value of the capital assets

The Stranded Gas Development Act gave the commissioner the authority to modify the current tax system within any gas line contract developed under the Act. There is no specific language in the Stranded Gas Development Act that dictates the level of payments to Municipalities that the contract must provide. The State in negotiating the contract language as it relates to Municipal revenues attempted to maintain an income stream of equivalent NPV during the life of the contract. Although the state acknowledges that the revenue stream from the GTP PILT is not equivalent to the income stream generated from a property tax on the GTP, the state estimates that the contract will make available, to the North Slope Borough, an additional $80,000,000 in annual gas related revenues once the pipeline is completed.

12. The Gas Unit of Production methodology must fairly treat inflation and depreciation

The 80% CPI factor is used to account for the effects of technology changes and depreciation on the existing and new upstream gas assets. As far as the use of the Urban CPI factor for measuring inflation, the contract sought to have a single inflation adjustment for all components of the contract. Although the particular factor chosen may not be oil field specific, it is a widely accepted measure of inflation.

13. Any gas valuation methodology has to meet the concerns of the North Slope Borough; The Gas Unit of Production method of assessment must protect municipalities from large revenue fluctuations

History shows that gas pipelines tend to run at steady and full capacity for a significant portion of their economic life. The state believes that PILT structure in the contract will result in a more stable and predictable revenue stream to the North Slope Borough than a status quo tax structure.

14. The Gas Unit of Production method of assessment must include a plan for review and re-implementation

The state agrees that the rate per MMBTU/MCF cannot remain fixed and must adjust over time. Rather than provide for reopeners that would result in fiscal uncertainty to both the producers and the North Slope Borough the state included annual inflation adjustments within the contract. A review of the cash flows from the PILT indicates that the inflation adjustment is sufficient to account for changing costs anticipated during the life of the contract.

15. The Contract should recognize the potential for cost overruns

The state fully understands that all parties take certain risks in locking in the PILT structure prior to completion of the pipeline. If the pipeline costs overrun, the PILTs might not meet the goal of equivalent NPV. Conversely, if major expansions occur that require less capital investment per MCF than the original project the PILT revenue could exceed the NPV of a status quo tax structure.

The state was fully aware of the concerns of impacts on communities during construction. The North Slope Borough, along with the Fairbanks North Star Borough has the advantage of recapturing revenues deferred during construction with the revenue PILTs. Other municipalities are actually being asked to shoulder more of the burden of the lost construction property tax revenue than the North Slope Borough. The need to address specific impacts during construction is why the construction impact PILT was included in the contract with the flexibility for funds to be allocated to the areas of greatest need. Section 18.1 of the contract establishes 125 million dollars in impact payment which will be appropriated by the legislature to those communities being impacted. The contract can hardly direct the payments to the affected municipalities since we do not now know which communities will feel what effects. The legislature can look at and balance relative needs, and coordinate those funds with other programs and spending. This will most likely be a less chaotic process than having every impact municipality trying to change its fiscal system for just the several years of construction, with all the attendant effects on other taxpayers within the municipality.

16. Any Contract reopener creates the potential for municipal losses

The reopener discussed by the governor was in reference to the oil tax provisions of the contract, and most specifically the production taxes. There has been no discussion related to the renegotiation of municipal PILTs.

17. The Contract audit and confidentiality terms must protect municipal rights

Technically, the contract is between the State and the industry sponsors. Municipalities are not third party beneficiaries under the contract. However, when the contract is read along with current law concerning mill rates, quite a bit of cash will flow to municipalities as PILTs, primarily the North Slope Borough. If the borough believes that it has not been paid appropriately, it must raise that issue with the State which will then act under the contract.

To be able to raise the issue though, the borough needs to have the information upon which payments are based. The vast majority of the NSB's payments will be driven by volumes and a close examination of the definition of "Non-confidential information" should reassure the NSB that volumetric and ownership information will be available. The only case where other information (property valuation records) is required would be for an oil pipeline under construction under article 17.2 (a). As that material is under the control of the commissioner there should be no problem in making it available to the Borough.

While we believe the concern raised by the Mayor is addressed in the contract, we could certainly look into expanding the definition of non-confidential information to include those specific pieces necessary for a borough to confirm their PILT payment.

18. Municipalities need the opportunity for dispute resolution

Your letter raises a question about the consequences if a producer, the midstream entity, or a participant does not make timely payment or any payment of the amounts due under Articles 15, 16 and 17 of the Fiscal Contract, monies which ultimately flow to the municipalities. Any delay in payment or failure to pay would subject the delinquent payor to an increasing obligation due to the interest that would begin the first day after the failure to pay. Article 26.2. The Contract provides that the amounts due under Articles 15, 16, and 17 are contractually owed to the State, and that only the State will have the responsibility for pursuing the amount due through the dispute resolution mechanism. As a consequence, the municipalities will have no direct remedy against the delinquent because the contractual obligation is to the State but the municipalities will have the right to seek redress from the State for the missing payment. *See* Article 21.3. ("A *Political Subdivision's* exclusive recourse is against the *State*").

The fundamental point is that there has to be a measure of good faith in assuming all parties to the Contract will carry out their obligations, especially the obligations in question. The calculation of the amounts due under Articles 15 through 17 is straightforward and leaves little room for dispute. The State is confident that the Article 15 through 17 payments will be made in the ordinary course of business and will not be delayed. Further, because the payments are due under a contract, not a statutory scheme of taxation, it was thought inappropriate to include penalty provisions as opposed to a requirement for interest.

One point raised by the question is whether the interest on the delinquent payment would flow through to the State. The Contract is silent on that point but we will consider adding language to address this. It would appear fair that some or all of the interest should flow to affected municipalities in appropriate circumstances. The relevant question would be how soon the State acted to relieve the municipalities of the consequences of the delinquent payment. If, for example, the State acted quickly to provide funds to the municipalities in lieu of the delinquent payment, then logically only a portion of the interest corresponding to the delay in passing through the funds to the municipality should be passed through. If, hypothetically, the State did not provide funds to the municipalities until it had resolved the dispute with the delinquent payor, then it

would appear all of the interest should be passed through. Because this is a prospective issue between the State and the municipalities, it should be addressed outside the Contract, which is concerned with the core obligations between the State and the Sponsor Group.

19. The Unit of Production methodology should not exempt line pack or field use

All gas and oil, owned by a signatory to the contract, that is transported through a pipeline segment is used in calculating the PILTs.

20. The inflation rates used in the Contract must be revised

The 80% CPI factor is used to account for the effects of technology changes and depreciation on a mix of existing and new upstream gas assets. The 70% factor is used to account for these same effects on the existing oil assets but further recognizes that fewer new oil assets are expected to come on line in the future changing the mix of new and existing assets and requi a greater recognition of obsolescence. As far as the use of the Urban CPI factor for measuring inflation, the contract sought to have a single inflation adjustment for all components of the contract. Although the particular factor chose may not be oil field specific, it is a widely accepted measure of inflation.

21. The Stranded Gas Development Act amendments must address unintended consequences of the PILT

We agree with your analysis of the school funding issue, and it was never our intent to diminish the school funding mechanisms. Thus as the outlines of the contract became clear, we requested (and both the bodies of the legislature accepted) language to make sure the assets which though tax free had associated PILTs, would remain in the tax base at full and true value. As part of the legislation the state will be required to value the assets in order to establish the proper level of state and local contributions to education. While this bill did not pass out of the legislature in the first special session, we encourage you to support this bill when it comes up in the next special session.

22. Contract provisions should take effect when the project is sanctioned

Recognizing that a purpose of the Contract is to drive the producers to a decision on sanctioning the project as opposed to a decision today to build the pipeline absolutely, you ask whether "most benefits to the producers under the contract should have a trigger date of project sanction" rather than from the effective date? In point of fact, the value of most benefits of the Contract will accrue if and only if the project is sanctioned. That is true, for example, for the essence of the gas benefits because the start of gas production triggers those benefits. The State considered the option whereby fiscal benefits would accrue only at sanction, but that was not the outcome of the negotiations. The Sponsor Group argued that they need certainty about the economics from the effective date because they would be making substantial outlays and evaluating the overall economic risk of the project from that time. For example, over the period of project planning, regulatory process, engineering and the other steps that lead to project sanction, the companies will spend up to $1 billion. The companies argued successfully that it was necessary to provide fiscal certainty from the outset to contain the risk of tax changes on the project economics, which are measured in a way that includes the early substantial outlays for the project.

23. The Contract must accommodate new local government formation in the Unorganized Borough

The contract provides a mechanism for new boroughs to receive a portion of the PILT associated with the gas line and TAPS. If in the future the gas line PILTs are insufficient to fully fund payments to new boroughs the payments would be prorated under the contract but the legislature could still act to make up the difference. TAPs PILTs are sufficient to fully fund payments to new boroughs.

24. The Contract must provide for baseline data collection and mitigation of effects

The State of Alaska relies on resource development to support the services provided to the citizens of the State. The State has always recognized the importance of balancing the need to develop natural resources with the protection of fish and wildlife habitat. The gas pipeline project, through FERC, will be subject to an Environmental Impact Statement with the State as a participant. In addition, the Department of Natural Resources Commissioner will perform a parallel public process prior to making a final decision on the right-of-way lease. These processes serve to identify possible impacts of the project, including environmental impacts. Mitigation of potential impacts is accomplished through existing law or through stipulations to the lease and grant of right-of-way.

25. Expanded exploration and development bring new impacts that must be addressed

The primary reason that the contract does not address impact payments from future development is that most of this development is anticipated to occur in NPRA or the OCS, and there are other mechanisms in place to address impact payments from these areas.

The construction and operation of the gasline, and any future gas exploration and development, will bring greatly increased revenues to both the state and North Slope Borough governments. In addition to the direct revenues, there is also the Coastal Impact Assistance Program that provides coastal political subdivisions (such as the North Slope Borough) with revenue from OCS oil and gas leases and activities

26. Local residents must be involved in planning

Any significant development on the North Slope will require numerous permits and authorizations. Most of the State and federal permitting processes (including State and federal oil and gas leasing and permitting programs) involve a public process designed to involve and gather input from the public and local residents. In addition to the permitting process, the State also has designed project permitting teams to work on proposed large

resource development projects. Part of the purpose of assembling those teams is to ensure that all issues and impacts of a project are considered and addressed. In addition, the Alaska Coastal Management Program ensures local review and input on development projects in the coastal zone, including the OCS.

Any significant development on the North Slope, including the gasline and associated facilities, will require a federal Environmental Impact Statement. As part of that EIS, there will be extensive public involvement opportunities during the development of an EIS, including compliance with the federal Executive Order 13084, Consultation and Coordination with Indian Tribal Governments. This directs federal agencies to establish regular and meaningful consultation and collaboration with tribal officials. This 'government-to-government' consultation means more than simply providing information about what the agency is planning to do and allowing comment. Rather, the consultation means a two-way communication that corks toward a consensus reflecting the concerns of the affected federally recognized tribes. This consultation is an important method for making sure that traditional knowledge from the local residents and elders is incorporated into the planning process for significant development projects.

27. North Slope residents need to be trained and hired for gas line jobs

The Alaska Department of Labor and Workforce Development was planning for the potential of a mega project when the decision was made to open a job center in Barrow. The role of the job center is to connect Alaskans with training and employment opportunities.

The Alaska Gas Pipeline project is an example of the mega projects. To design, build and operate the Alaska Gas pipeline will require skilled workers in many fields. The most common occupations in demand for the project are welders, heavy equipment operators, truck drivers and general laborers. Preparing Alaskans for these occupations requires specialized facilities and equipment.

Congress allocated $20 million for the training and development of workers associated with construction of an Alaska Gas Pipeline. $3 million has been earmarked for a specialized training facility to be located in Fairbanks. Fairbanks was chosen because of the extreme temperatures that are similar to those experienced along the proposed route and its reliable access to transportation, resources and other community supports. Employees of the local job centers are prepared to assist rural residents to obtain training from the Fairbanks training facility and other facilities that will help an individual prepare for work on the project.

Additionally, the department is developing alternative training strategies that will bring training opportunities closer to rural communities but still provide the same level of quality. An example of the new training strategies is the construction academies that were held in several rural communities and regional hubs. Where appropriate, the department will seek to improve local access to quality training.

28. Solid waste issues need to be addressed in planning for the gas line

Hazardous and solid waste issues will be addressed in the right-of-way leasing process. The lessee will be required to develop a solid and hazardous waste plan prior to receiving a notice-to-proceed for construction. The plan will be available for public review as part of the DNR Commissioner's proposed decision.

29. The TAPS corridor must be closed for security and wildlife protection

It is the policy of the ADNR that access roads and the right-of-way, including work pads, will be open for the use and enjoyment of the public unless the Commissioner approves the regulation/restriction. Upon completion of construction of the pipeline, the public will have access along the right-of-way, except at compressor stations, other permanent facility locations, areas where the pipeline is above-ground, and locations where access must be limited for security or safety purposes. Access roads leading to the right-of-way, whether currently existing or constructed by the lessees, may, with the

Commissioner's approval, have limited public access during construction and termination activities. At all other times, unless the lessee receives the written permission of the Commissioner to restrict access for operation and maintenance or public and wildlife safety purposes, the pipeline right-of-way access roads must remain open for public access. If public access is limited on existing highways, trails and access roads, the lessee must provide alternative routes. The lessee must also provide appropriate warnings and safety measures when using access roads or when limiting public access to the access roads.

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August 31, 2006

Senator Gene Therriault
Alaska State Legislature
119 N. Cushman Suite 101
Fairbanks, Alaska 99701

Dear Senator Therriault:

This is in response to your July 24 letter to the Murkowski Administration regarding the Alaska Stranded Gas Fiscal Contract between the State of Alaska and BP Exploration (Alaska) Inc., ConocoPhillips Alaska, Inc. and ExxonMobil Alaska Production Inc. /Preliminary Findings and Determination.

The Murkowski administration's gas team has carefully considered your 49 pages of comments on the Stranded Gas Fiscal Contract. Your comments were grouped into four summary issues, followed by contract modification recommendations. The four summary issues you presented are:

1. Market dynamics have changed significantly since passage of the SGDA;
2. The Contract is not ripe for consideration or execution because it fails to address critical issues;
3. The Contract represents an unbalanced set of commitments and obligations; and
4. The findings suffer from factual errors, incorrect treatment of shipping commitments and misplaced fears regarding LNG.

We do not agree with your characterization of these issues. This document provides our reasons, and a response to your Contract modification recommendations.

Response 1: Variations and shifts in the North American market dynamics have not undercut the premise or the justification for the SGDA.

The proposed contract between the Participants and the State is a Stranded Gas Development Act "fiscal" contract that was never intended to mitigate the volatility of natural gas prices. The purpose of the Stranded Gas Development Act was to *"allow the fiscal terms applicable to a qualified sponsor or the members of a qualified sponsor*

Notwithstanding, arguments that market dynamics are fundamentally changed are without merit. The December 2004 Division of Oil and Gas price forecast is very similar to the 2006 division gas price forecast (just released) during the timeframe that startup of the Alaska Gas Pipeline is projected – a mean value just over $4/MMBTU in 2006 dollars. During the timeframe 2020 through 2040, the mean 2006 gas price forecast exceeds the mean 2004 forecast by about $1/MMBTU. And regardless of these price forecasts, no one can say with any certainty what prices will actually be over the term of the Contract.

While the fiscal contract provides for a stable fiscal regime, there are many other risks and uncertainties. In addition to the natural gas market, some of the other concerns include:

- Litigation - The fiscal contract or the law authorizing the contract may be challenged in the courts. The time period required to resolve this type of litigation is uncertain. There is also the potential for other litigation as the Project advances.

- Procurement – The Project may face cost increases (e.g., steel) and material/labor shortages. As a case in point, in the five years since the Producers completed their $125 million study, steel prices have increased dramatically.

- Open Season - In any open season, there is risk of insufficient market support. At a minimum, there could be delays due to third party challenges or the need tc make significant and costly design changes as a result of the open season.

- Regulatory - The Project faces permitting requirements in both the U.S. and Canada. These are complex processes involving multiple agencies, with potential overlapping terms and conditions.

- Construction – Due to the massive scope of the Project, there could be many unforeseen risks and uncertainties, including the need for and performance of new technology, pipeline lay rates, labor disruptions, weather during construction and timing of construction and sea lift windows.

- Resource - Roughly 30% of the needed reserves will have to come from unexplored fields.

The SGDA was not created to remove all risks. Its focus was to reduce risks related to changes in Alaska government take by providing fiscal certainty. Government take is the single largest cost to investors and only one of many types of risks that will affect this long-term project.

<u>Response 2:</u> The fiscal contract is ripe, and the time is right, for authorization and execution.

The fiscal contract addresses those matters that belong in the fiscal contract, allowing those matters that belong in operating documents or that are subject to state policy to be addressed appropriately. The proposed fiscal contract – on the table today – offers the State the best opportunity to get a gas pipeline built, under the best terms the State can expect to have available. Specific concerns you raise are addressed below:

LLC Agreement. The Mainline LLC agreement will be available prior to final consideration of the fiscal contract by the Legislature. Other LLC agreements, and Canadian partnership agreements, will be developed, patterned after the Mainline agreement, as those entities are formed during the project planning process.

Coordination Agreement. The need for a "coordination agreement", as well as the terms of such an agreement, remains a matter of discussion both within state government, as well as with the producer companies. However, while coordination is recognized as important to the execution of the Project, it is not pertinent to the fiscal terms of the agreement, and there is no need to address the mechanics at this time. Details of project execution will be addressed in the project planning phase – which will begin within 90 days after Contract execution.

Parent Guarantees. The Sponsor Group companies have consistently maintained that parent company guarantees are not needed. The Sponsor Group companies, who are the parties to the fiscal contract, state that they hold significant assets in Alaska and have the financial wherewithal to fulfill the obligations under the Fiscal Contract. Before executing the contract, the State will require satisfaction that the Sponsor Group companies that execute the contract have the very large resources needed to ensure performance of the contract.

Regulatory approval plans. It is unreasonable to hold up approval of the fiscal contract for development of additional Canadian and US regulatory approval plans. Such work will be part of the planning process that will start within 90 days after Contract execution. A proven process to permit a cross-border pipeline already exists in Canada.

Commitment to subscribe to shipping capacity. The technical answer is that this is a fiscal contract, not a shipping contract. The shipping commitment logically does not precede the fiscal contract, but follows it, in the open season required under FERC regulations, which cannot be held until considerable engineering and commercial work is completed and notice to all prospective shippers is made. The practical answer is that the producers have exhibited commitment to the Alaska Gas Pipeline by spending 125 million dollars in preplanning, by lobbying for the federal legislation (ANGPA of 2004), and by negotiating and agreeing to the fiscal contract, which includes a commitment to accept a substantial increase in production taxes subject to Legislative enactment, and associated work commitments to advance the project. The sponsors are resource owners, and the pipeline project is ancillary to and designed to enable the commercialization of those resources. In that light, it is not reasonable to

assume that, after all of this effort and after executing the fiscal contract, the producers will simply stop in-place; delaying the monetization of the North Slope gas resource, risking termination of the fiscal certainty they receive under the contract, and facing the consequences of subsequent State reaction.

State Marketing Arrangements. The administration is unwilling to allow the producers to have any control over the structure of the State's marketing entity or of the State's in-state gas pricing policy. The State has an experienced gas marketing professional on staff, has been developing a gas marketing plan, and is working toward developing a state gas marketing entity. The administration has also drafted an in-state gas pricing policy for consideration, and has been meeting with individuals and entities around the state further exploring a policy which works for all Alaskans. The administration will not accept producer involvement in either issue by including them in the fiscal contract.

AOGCC Offtake Allowables. The fiscal contract in no way limits the authority of the AOGCC. As a matter of fact, the AOGCC has begun reviewing PBU gas offtake rates, and will address PTU offtake rates in the near future. White papers on the AOGCC web-site make it clear that the Working Interest Owners for both PBU and PTU and the staff and consultants to the AOGCC are advancing the work to allow the Commission to issue conservation orders that provide allowable gas offtake rates prior to any open season. Article 23.1(c), reinforces this process by requiring the Sponsor Group companies to apply to the AOGCC for PTU pool rules within six months after the Effective Date.

Response 3: The fiscal contract provides the proper balance of risk management and commitment on the part the producers, as well as the State.

The Alaska Stranded Gas Fiscal Contract is a fiscal contract. The fiscal contract provides fiscal certainty in exchange for a commitment to move forward on making an Alaska Gas Pipeline a reality. The Administration's economic modeling demonstrates that, under the fiscal contract, the State has retained the value under the current fiscal regime (tax and royalty) while reducing project risk and improving overall project economics significantly The State determined that fiscal certainty on oil was appropriate, only after the producers agreed to accept a hefty increase in oil taxes (over $1 billion annually at current oil prices), subject to Legislative enactment. Therefore, while oil fiscal certainty is provided under the fiscal contract, the producers are paying a substantial price for it.

The work commitments and the diligence standard negotiated in the contract were carefully constructed to balance the State's need for commitment and enforcement with proper risk management of this enormous international project. The producers commit, unreservedly, to start project planning within 90 days of contract execution; and to conclude project planning activities with a decision whether to begin preparation of regulatory applications and planning for an Open Season. During the project planning phase, the Participants will:

- conduct additional technical studies to facilitate selection of a preliminary project design basis;

- develop Project cost estimates and schedules for all Project phases;
- update economic analyses;
- prepare the work scope, staffing plan and cost estimates for the next Project phase;
- select contractors for the next Project phase;
- develop plans for access and regulatory/permit applications for both the U.S. and Canada; and
- establish commercial structure and tariff principles to guide Project development.

The Participants also commit to "continue to pursue implementation" until Project Sanction. The final deliverable of Article 5 of the Contract is Project Sanction. The Participants' obligation to progress the project is firm. If the contract is challenged in the courts, as many expect will happen, the Contract requires that the Participants continue to progress the Project. In the event of a court challenge, when the very contract benefits for which the Participants have negotiated are being challenged and are at risk, the Participants must, consistent with Article 27.2, continue to perform their obligations until Project planning is completed, fifteen months has elapsed, or $120 million has been spent. This is in addition to the $125 million spent during 2001 and 2002 to study and evaluate the feasibility of this Project.

The fiscal contract stipulates a standard of performance; that the project be advanced as diligently as is prudent under the circumstances. Prudence is a key component which seems to have been neglected in discussions about the diligence standard. The administration was able to capture the relevant elements of the "prudent operator standard" within the contract standard, as is explained below.

Articles 4 and 5 of the fiscal contract reference the Qualified Project Plan which provides a success-based estimate of project scheduling and delivery dates. On May 10, 2006, the Sponsor Group filed a public project summary that contains the most current information on the success case for project development, including a timeline with associated activities. The plan, schedule and dates will change as project planning progresses, new information becomes available, implementation issues arise, issues are resolved, and the project moves through the stages of implementation. Each year a Project Summary will be created which will include an update to the project schedule. The Project Summary is a public document that can be used to understand the progress being made on the project.

One of the biggest concerns for the state is the risk of cost overruns. The adverse affects to the state of cost overruns are manifold: Overruns will not only increase the pipeline financing burden for the state, but will reduce the value of the state's royalty and tax gas, increase negative price risk, reduce the value of the state's leasehold acreage, reduce the level of investment in North Slope exploration, and increase reserves risk later in the contract term.

The Alaska Gas Pipeline project not only has a significant risk of incurring cost overruns, but also has a significant risk of those overruns being massive. The Alaska Gas Pipeline is considered a "mega-project" not only because of the pipeline size and

length, but because of its magnitude relative to international steel and labor markets, the interaction with upstream and infrastructure development timing, and because of the multitude of jurisdictional and international issues involved. Mega project cost overruns exceeding 50% of project sanction cost estimates are not uncommon.

Cost overrun risk is minimized by careful and complete alignment of project resources in a disciplined approach to project planning, permitting, design and approvals. Competing priorities, such as artificial deadlines or avoidance of 'penalty payments' result in conflicted decision making, leading to compromised results which begin the spiral into escalating cost overruns.

The State's direct equity participation in the project actually provides a "hedge" against this overrun risk, as the State will earn a return on the capital invested in the pipeline through the tariff revenues it will receive as a pipeline owner. This "hedge" is not available to the State under the "status quo".

Response 4: The draft fiscal interest finding

Your comments concerning the draft fiscal interest finding will be responded to fully in the commissioner's formal response to comments received during the public comment period. Your comments and your conclusions largely reflect a distorted view of the use of corroborating evidence to support fundamental revenue and cost data, and international mega project risk experience; and an inadequate appreciation of the reasonable range of possible economic outcomes.

The assertion that "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" is incorrect. The gas has not been brought to market before now because the producers have not been able to economically justify the magnitude of, and the risks attendant to, the investment required; given the market prices historically available. Certainly, had they been able to place an economic project on the table, the State would have been faced with just the tradeoffs you imply. Such a decision was never presented to the State.

LNG imports certainly continue to face environmental hurdles; however, permits for construction are being approved, particularly in the Gulf of Mexico, where the bulk of import capacity into the central North American gas markets originates. As these facilities become more commonplace and the public better informed; and as need grows, we can expect that such hurdle may well fall.

As important as the Federal financing guarantees are to the Alaska Gas Pipeline project, they do not protect the producers. They are guarantees extended ultimately to the financing entities that loan money to the project entity. Producers remain responsible for guaranteeing completion of the project. In addition, liability will remain with those who seek the financing until the project is in-service.

Response to Contract Modification Recommendations:

You provided recommendations, under 15 subheadings, for fiscal contract modifications, primarily with the stated intent of receiving "commitments which will lead to development of stranded gas." While we offer the following responses to your recommendations, we are considering your recommendations along with the rest of the public comments as we prepare the final finding and proposed amendments:

Work Commitments, Diligence Standard, and Qualified Project Plan

- Specific activities and the timeline associated with each activity are in fact set out in the Qualified Project Plan, and are documented in the public Project Summary, which must be updated annually.
- On May 10, 2006, the Sponsor Group released an updated Project Summary that was filed as part of the Qualified Project Plan. The May 10 update lays out a timetable and schedule of activities for a success case.
- Consistent with good project management practices, milestones and completion dates will become more detailed and will be revised, as project planning proceeds. The detail you seek is produced during the project planning process.
- Assuming that the Fiscal Contract is approved, the State, as a member of the Mainline and related LLC's, will participate in and supervise project development along with the other members of the LLC's. This is a primary benefit of having a seat at the table. The producers and the State will be working together towards project implementation.
- As part of his overall responsibilities, the Governor and his representatives will monitor implementation of the Qualified Project Plan to ensure that the contract requirement that the project be advanced "as diligently as is prudent under the circumstances" is fulfilled. Because the next phases are spelled out in the May 10 Project Summary and because each activity requires the expenditure of substantial sums of money, it will be a straightforward process to observe and measure the progress of the project both from the perspective of the State's membership in the pipeline LLC's and from the outside.
- Prescription of termination or penalties for failure to meet a milestone on the Qualified Project Plan creates an artificial priority which is very likely to compete with sound project management priorities, thereby increasing the risk of poor decision making and incurring cost overruns trying to meet that artificial priority. Penalties do not protect the State – they add to the risk of this project for the State. Cost overruns will increase tariff rates. The State's greatest interest, like the Sponsors', lies in the value of the gas resource. This value would be eroded by high tariffs due to cost overruns. Thus, the State should not include terms in the Contract that increase the risk of cost overruns.

- Article 5.5(a) gives the State the right to terminate the Contract up until Project Sanction if the producers fail to continue to advance the project 'as diligently as prudent under the circumstances'

- Diligence is defined in the contract as advancing the project as diligently as is prudent under the circumstances. The concept of prudence is already integral to this definition. The "Prudent Operator Standard" to which you refer is applied most often to production operations, rather than planning and permitting a major international construction project. The Diligence standard incorporates this concept of prudence into the standard of performance imposed by the contract.

It is understandable that Alaskans, having waited so long, want to see a project as quickly as possible and hope for an unconditional promise to build a project by a certain date. The State shares that objective but must face the realities of how large international regulated projects are built. No construction can start without prior approval and authorization from the FERC in the U.S. and the NEB in Canada. Before an application to those agencies can be submitted, an open season must be held that will secure hopefully large shipping commitments for use of the pipeline. And before that detailed engineering and field work have to occur in order to satisfy the FERC's regulatory requirements for the public notice that kicks off the open season and for the application itself. Parallel activity must occur in Canada. The expected timeline for these activities, a realistic but not artificial timeline, is contained in the May 10 Project Summary.[1]

With these required steps and past experience in mind, it is wise to recall the briefing that you and other members of the Legislature have been briefed by ILA, specialists in large project planning. A critical lesion was that projects that are driven by a tight schedule commonly encounter cost overruns, poor execution, or ultimate delay. Setting up a system of penalties, as you urge, would contravene the lessons that ILA taught. The priority will likely become avoiding penalties, not soundly advancing the project. This is not sound project management and could lead to poor decisions and cost overruns with an increased likelihood of after the fact repairs and reconstruction of parts of the pipeline.

The State does have the sanction of termination of the project under Article 5.5(a). This is a serious step, so serious that it has been criticized as a nuclear option. If the contract is terminated, then the producers lose all of the fiscal certainty that they have negotiated so hard to achieve. In such event, the State would be free to change taxes and incentives in any way it thought good public policy deserved. These consequences should not be lightly disregarded.

You suggest that the sponsor should be held to a standard or prudence or that the prudent operator standard should be applied. Since diligence is defined as advancing the project as is prudent under the circumstances, the concept of prudent is a central

[1] In the first effort to build an Alaska gas pipeline, President Carter's Decision and parallel agreements with Canada established an expected in service date for the winter of 1982. That expectation was never realized. The sponsors of that project repeatedly pushed the project schedule back as they encountered regulatory, financing and gas market difficulties.

part of the standard. The prudent operator standard is a standard that is applied in conjunction with lease development, not midstream element development. Nonetheless, the mainstream interpretation of the prudent operator standard suggests that it is closely related to the diligence standard in the contract. Williams and Myers, the leading oil and gas treatise, quote an opinion of the Supreme Court of the United States in explaining the concept. The Court begins by emphasizing that both lessor and lessee are "bound by the standard of what is reasonable," that a breach can occur even where the lessee has applied some measure of diligence but "no breach can occur save where the absence of such diligence is both certain and substantial in view of the actual circumstances at the time, as distinguished from mere expectations on the part of the lessor and conjecture on the part of mining enthusiasts. . . whether or not in any particular instance such diligence is exercised depends upon a variety of circumstances. . . Whatever, in the circumstances, would be reasonably expected of operators of ordinary prudence, having regard to the interests of both lessor and lessee, is what is required." Section 806.3.

The work commitments clause uses the language "clear and convincing" for the standard as opposed to "certain and substantial" but the meaning of the words is quite similar. The prudent operator standard refers to actual circumstances and a variety of factors. The work commitments clause also suggests reference to a variety of circumstances and endeavors to provide some guidance on what might be relevant or not.

The State is reviewing the work commitments clause to see whether it can be improved or the explanation of its operation improved in view of the public comments. But it believes that a fair, real world reading of the clause, as explained, shows that it is a meaningful obligation with a tough penalty for its breach. It should be noted that Dr. Van Meurs, with vast experience in international projects, has confirmed that this is as good or better than any work commitment clause of a major project.

Expansions and Sole Risk Expansions

- The State expects that the pipeline will be reasonably sized to accommodate present and future production consistent with FERC precedent. At the urging of the State and others, the FERC has said that when the initial application for the pipeline is received, it will review it to be sure that it is properly sized to accommodate present and future needs.

- The State has an economic interest in justifiable pipeline expansions that meet export needs from the North Slope and other producing areas within Alaska. However, as an initial shipper, the State also may have an economic interest in not subsidizing transportation costs of expansion shippers. Based on potential on the Alaska North Slope, exploration success is likely to be on non-State acreage which would have no associated State royalty, and possibly no tax gas.

- A new shipper can be accommodated by 1) contracting with holders of existing capacity, 2) a 'reverse' open season, or 3) expansion of the pipeline.
- For the Alaska Gas Pipeline, expansion can be addressed in three ways: 1) voluntary expansion by the pipeline owners, 2) mandatory expansion authority granted to FERC, and 3) State-initiated expansion under the Fiscal Contract.
- Voluntary expansion is a business decision that will be made under the governance of the LLC agreement. By their very nature, provisions for a voluntary expansion belong in the LLC agreement, not in the Fiscal Contract.
- Future expansion needs and timing cannot be predicted or reasonably preplanned today. Need for expansion could arise at various points over many decades, and the circumstances of each could vary considerably.
- FERC authority over open seasons and expansions, as broadened specifically for the Alaska gas pipeline under the Alaska Natural Gas Pipeline Act, will protect the interests of expansion shippers and facilitate expansions:
    - FERC rules require that the initial pipeline design provide for expandability.
    - FERC rules provide that anchor shippers cannot prevent other creditworthy shippers from receiving capacity at an open season.
    - FERC has the authority to mandate expansion on this (and only this) pipeline.
    - FERC will be motivated to oversee this pipeline closely due to its significance to US markets.
    - FERC rules establish the presumption of rolled-in pricing.
- Open seasons, whether binding or not, are expensive events to hold. These costs are not incidental. They entail significant interaction with FERC, including pre-approval of the open season process. An arbitrary commitment to hold periodic open seasons is a significant burden upon the pipeline owners – including the State. The costs of unnecessary open seasons must either be borne by the pipeline LLC members, including the State; or be included in the tariff paid by the shippers, including the State.
- Commitment to satisfy all creditworthy demands for capacity expansion, with or without contributions in aid of construction, places the pipeline in a disadvantaged position determining the timing of open seasons and in negotiating with new shippers. Such a commitment will impair the ability of the pipeline to manage expansions effectively, under the watchful eyes of the FERC and the State.
- A blanket commitment to propose and defend the use of rolled-in pricing for all expansions places the existing owners and shippers – including the State – in the position of encouraging and ultimately underwriting uneconomic expansions. Proponents of such expansions would have a tremendous economic incentive to

pursue any expansion, even one that is uneconomic, since the costs would be spread among all shippers.

- A sole-risk expansion provision would burden the State with 100% of the risk associated with any expansion of this type it undertook. The State negotiated the State-initiated expansion provisions to provide the State with a more direct tool with which to ensure needed expansions occur, without assuming 100% of the risk associated with those expansions. A sole-risk expansion could also adversely increase the costs or reduce the feasibility or efficiency of later expansions. It would also cause considerable administrative and operational complexity within the LLC to deal with the "independent" pipeline addition.

Article 8, including RCA Jurisdiction

- Nothing in the fiscal contract prevents the Regulatory Commission of Alaska from exerting jurisdiction over facilities over which the FERC does not exert jurisdiction.
- Affirmation of RCA jurisdiction is the right and responsibility of the RCA itself.
- The State has agreed to reimburse the producers for certain losses incurred due to RCA regulation in the unlikely event that the FERC does not assert jurisdiction over all elements of the project in the U.S., and the RCA does. Even then, the relevant standard will be whether the RCA jurisdiction, if lawful, is inconsistent with FERC principles, and if so, causes actual loss other than lost profits, which are excluded from the recovery.
- Mention of the NEB in Article 8 simply acknowledges the role of the NEB in Canada as the sole Canadian regulator of inter-provincial pipelines, just as FERC is the sole US regulator of interstate pipelines. Alternative Canadian construction permitting avenues may exist in Canada; however, Canadian law provides that any inter-provincial pipeline will be regulated by NEB, as we have acknowledged in the Fiscal Contract.
- The rate treatment of previously used assets is but one of many facets of FERC regulation that should be left to federal law and FERC policy to which this project is subject.

Capacity Management

- The State insisted upon the Capacity Management provisions of the contract to reduce its risks associated with taking royalty and payment in lieu of production tax in the form of gas. As such, these are core provisions of the contract, and were carefully crafted.

- Precedent suggests that FERC will be responsive to the State's position as a shipper, and our very different upstream position with respect to the producers when they deliberate to ensure an 'even playing field' exists for capacity rights[23]

- If FERC fails to approve all of the Capacity Management provisions, it is expected that it will provide the State and producers guidance to satisfy both FERC requirements and State needs. The producers are committed in Article 10.8 to negotiate in good faith in an attempt to develop a mutually acceptable alternative provision that remedies the defect.

Term

- Fiscal stability on oil is granted under the contract after a hefty severance tax increase, due to the integrated nature of the producers' oil and gas portfolios and investments. The Legislature will have the final word on the length of fiscal stability.

- Likewise, on gas the Legislature will have the final word on fiscal stability.

- The term or duration of the fiscal contract commences when executed by the State, BP, ConocoPhillips and ExxonMobil (the "effective date") and remains in effect for 35 years from the commencement of commercial operations, with a few exceptions. Certain oil related and income tax provisions carry a shorter term. In particular, the term for the payment in lieu of production taxes, payment in lieu of pipeline ad valorem taxes and for the State corporate income tax is 30 years from the effective date.

- Due to the integrated nature of the producers' oil and gas assets and investments, the state determined that this fiscal stability on oil is appropriate. However, the state granted that stability only after a commitment by the Sponsors to a hefty severance tax increase, subject to Legislative enactment.

- Fiscal certainty on a $20 billion-plus gas pipeline project is critical to the advancement of the project and is at the core of the Alaska Stranded Gas Development Act.

- On two separate occasions the Alaska Legislature has spoken on the subject of the term of a fiscal contract. On both occasions the legislature clearly indicated that a fiscal contract could be developed for a term of 35 years from commencement of commercial operations. First, in 1998, the House passed the SGDA bill with 35 votes in favor and the Senate had 20 votes in favor. The legislature sent an even clearer message in 2003 when reauthorizing the SGDA. The House unanimously passed the reauthorization and the Senate had 19 votes in favor, with one party excused. Thus, the legislature correctly anticipated in 1998 and again in 2003 that a

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[2] *Columbia Gas Transmission Corporation*, 97 FERC P 61,221 at 62,004 (2001).
[3] *Sabine Pipe Line LLC*, 113 FERC P 61,312 at P 5 (2005).

project of this magnitude would require a 35 year term starting at commencement of commercial operations.

- If everything goes according to the success-based plan contained in the Project Summary provided to the DOR Commissioner on May 10, 2006, the gas pipeline project is anticipated to take 9-10 years from the start of project planning until the commencement of commercial operations. The term of the contract would then remain in effect for an additional 35 years for a maximum of 45 years. The hard line of 45-years accomplishes two things.
    - First, it ensures that if the construction phases of the project extend beyond ten years, the fiscal terms, including fiscal stability, are not extended. This is one more reason that the producers will advance the project as diligently as is prudent under the circumstances. Any delay results in a shorter fiscal stability period following commencement of commercial operations.
    - Second, since the fiscal contract cannot extend beyond 45 years, it makes clear that the fiscal stability is temporary, not permanent.
- Thirty-five years of fiscal certainty during production is not uncommon in large oil and gas related projects. The State's consultant, Dr. Pedro Van Meurs, analyzed a number of international agreements. Based upon his data, it is clear that many countries offer contracts for fiscal stability that include 30 years or more of production. In fact, a recently completed multi-billion dollar Caspian Basin pipeline project includes a fiscal stability term of 60 years. In many cases, at the end of the primary term of those agreements, there is an extension if the asset is still producing. International precedent not only includes extensions for continued production, but there is precedent for "life of field" terms for gas. Prudhoe Bay Unit alone will likely be producing gas for at least 35 years from first gas, depending on the offtake rate established by the PBU owners and the AOGCC.
- While there are numerous upstream production sharing contracts with terms of 35 years or more, it should be noted that the Alaska Gas pipeline project is a midstream mega-project rather than an upstream project, and relative to "model" international gas projects, the Alaska gas Project is two to three times larger in capital costs and is higher risk than most international projects. Specific risks associated with the Alaska gas Project include: (1) the inherent size and cost of the Project and its impact on labor and material markets, (2) the distance from market, (3) the rugged terrain and harsh construction conditions, (4) the limited infrastructure support, (5) the required coordination with multiple government jurisdictions, and (6) the volatility of gas prices. In fact, at an assumed investment of $20 billion, the Alaska pipeline Project would be the largest private investment in North America and is significantly larger than most "model" worldwide oil and gas projects. Many of these risks can be managed through disciplined project execution, particularly by companies such as the Producers who have experience in successfully delivering large projects around the world. Following international precedent, the producers argue, the significantly larger Alaska Gas Pipeline project with its inherent risks could reasonably expect to

have a fiscal stability term that is significantly longer than the 35 years from commencement of commercial operations contained in the Fiscal Contract.

- The term provided for in the Fiscal Contract will facilitate many years of continued investment and exploration. It could mean the development of a new gas exploration business and the corresponding upstream developments. The Project itself is based on having at least 50 TCF of gas produced on Alaska's North Slope. Production of this gas will take the full term of the Fiscal Contract. In fact the Project is dependent on those gas volumes to ensure that the economies of scale are achieved.

- Finally, there is a precedent for the State of Alaska entering into long term oil and gas related contracts -- the State has entered into lease agreements and royalty settlement agreements with individual taxpayers that remain in effect for the life of the field, which is the time required to extract all the hydrocarbon resource.

Price Differential Payment

- A "price differential payment" is not contained in the publicly released draft of the contract. This section of your comments constitutes a breach of the confidentiality agreement that you signed and the confidentiality commitments under which the fiscal contract was negotiated as required by the Stranded Gas Act.

- The administration does not understand why this issue was considered relevant to current deliberations

Suppression of the State's Regulatory Regime (Article 41.2)

- Article 41.2 was carefully drafted to provide for clarity where the fiscal contract provisions apply. All parties, including the State, must have confidence that the terms that have been negotiated are the terms that will apply to them.

- Leases, other agreements, regulations, orders and decisions are amended "only to the extent necessary to conform to the provisions of this Contract." All other provisions of these documents remain in full force and are not affected by the contract.

- This article does not result in "suppression of the State's regulatory regime".

Modify the Take Point

- The Contract establishes the delivery point for the State's gas at the same point gas is available for taking by the other producers. This enhances commercial alignment throughout the scope of the project.

- Moving the take point for State gas away from the unit boundary to delivery points in Alaska or Alberta would fundamentally alter the commercial arrangement negotiated with the Sponsor Group. State gas, State transportation commitments and State ownership in the pipeline are inextricably linked. If a producer transported State gas to the delivery point, that producer would have to hold the firm transportation.
- FERC does not allow shippers to ship third-party gas. Shippers must have title to any gas they ship.
- If the State takes delivery of State gas at AECO, the producers will hold the shipping commitments for the State's gas to that point. Removing that responsibility from the producers is the basis for improving producer economics, providing the State with the best opportunity available to get a pipeline built.

Exhibit D and Supply Commitments

- The leases listed in Exhibit D are part of the fiscal certainty negotiated in the Contract. That certainty will terminate if the contract is terminated. The addition of new leases to Exhibit D is subject to: 1) the enactment of the Uniform Upstream Fiscal Contract, and 2) delivery of gas to the project within 15 years (state leases) or 20 years (non-state leases).
- Limiting Exhibit D to those properties that will supply gas for the initial capacity prevents explorers and other third parties from obtaining a 'level playing field' for exploration and access to the pipeline for future deliveries, and does nothing to reduce the reserves risk of the project, to the State, later in project life.

Disputes, Arbitration and Choice of Venue

- As discussed above, leases, other agreements, regulations, orders and decisions are not amended unless necessary to conform to the Contract; hence, administrative and regulatory disputes over these non amended items would not be subject to arbitration.
- Disputes arising under the Contract are subject to arbitration designed to ensure a neutral, unbiased process. Disputes arising under the LLC Agreement will be resolved through court procedures.
- The LLC Agreement is under Delaware law for reasons previously explained.
- The fiscal contract is a complex agreement that could remain in effect for 45 years. The project is a $20 billion plus undertaking and the fiscal contract contains significant rights, privileges and obligations that flow back and forth between the State and Sponsor Group over this period. Disagreements are inevitable. The

parties must have an efficient and effective means of resolving disagreements when they arise.

- The parties selected binding neutral arbitration as this mechanism. Under this approach, no party has given up the ability to enforce its rights. On the contrary, an arbitrator will enforce the fiscal contract in a neutral fashion. In fact, the Alaska Supreme Court has recognized a public policy in support of arbitration. Moreover, there is precedent for arbitration: the ANS royalty settlement agreements between each Sponsor and the Department of Natural Resources provide for neutral arbitration.

- Article 26.1 is being properly interpreted. All disputes under the Fiscal Contract, with a few exceptions within the PPT provision, are subject to arbitration. Fiscal Contract disputes are between the State and a Participant or, in a few specific instances, the State and a group of Participants.

- There will be no overlap between the Fiscal Contract and the LLC Agreement. The dispute resolution provisions in the LLC Agreement will govern the members of the LLC, which will include the Alaska Gas Pipeline Company.

LLC, Coordination Agreements

- The LLC Agreement for the mainline is close to finalization but still subject to further negotiation. It will be released to the public when it is finalized. That agreement will serve as a template for other LLC Entity Agreements. Delaying the project to have **all** entity agreements executed prior to the fiscal contract is unnecessary and not in the best interest of the State.

- Normally these agreements would not be completed and public until the submission of FERC applications (approximately 2 years after the start of Project Planning).

- Coordination between the Alaska LLC and Canadian Entity can be achieved in various ways including a "Coordination Agreement". Cross-border pipelines have been done before – coordination can be managed among the project entities in the US and Canada, and will be addressed as part of project planning.

Summary

The Stranded Gas Fiscal Contract is the product of intensive negotiations between the Producers and the Administration that have taken well over two years to complete. By the very nature of a negotiation, the parties made trade offs to reach this agreement.

Neither the State of Alaska nor the Producers were able to achieve everything they wanted in the contract. Both sides were required to compromise to reach agreement. The agreement that has been reached provides the best opportunity for a gas pipeline project to become a reality, and allows the State to generate billions of dollars of revenues that would otherwise be impossible. The Fiscal Contract should be evaluated in that context.

We are assessing the public comments and will be seeking changes to the fiscal contract as a result of that assessment. At the conclusion of this process, we would encourage you, the Legislature, and the public to evaluate the final contract as a whole rather than focusing solely on isolated components. The Fiscal Contract that the Administration will present to the Legislature will balance risks and rewards and allow the Alaska Gas Pipeline Project to move forward. When that occurs, you and the other members of the Legislature will hold the keys to Alaska's future. We encourage you to vote in favor of that future by supporting the fiscal contract.

Very truly yours,

William A. Corbus
Commissioner

Copy to: Senator Ralph Seekins

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Date: August 31, 2006

Senator Gene Therriault
Representative Ralph Samuels
Legislative Budget and Audit Committee
State Capital, Room 119
Juneau, AK 99811

RE: Eason Comments

Dear Chairmen:

The administration message delivered on July 6, 2006 concerning gas-in-kind has been misconstrued in a memorandum, dated July 24, from LB&A consultant Mr. Jim Eason to the Chairman and Vice Chairman of the LB&A committee. The purpose of this memorandum is to restate the administration message, and to clarify the written record.

The intent of the administration in bringing up the MMS experience with in-kind sales was stated by Ken Griffin in the July 6 hearing:

> "What this MMS information leads me to suspect is that; (1), the costs of administering a marketing organization, however, we decide to do that, are probably - we were probably, quite conservative in estimating those costs, in what we've done. (2), one of the things that's missing from this analysis are the legal costs of evaluations, in the last 30 years. Those costs, looking at this probably will go away to a large degree moving forward. That's something that's not addressed really in our economics. And then the third thing: We did not put any value on keting. We're going to pay, we have in our economics a five and a half c t per mcf marketing burden. We didn't ascribe any value to that. So in three ways here, I think we've been conservative in appraising the value of taking gas in-kind. And frankly I'm very satisfied with that. That's the way it ought to be done."

First of all, this summary statement was couched by the administration in tentative terms. Second, the cost burden included by the administration in developing the Contract economics may well be high. Third, the benefits to the

state of potentially reduced litigation costs and the problems created by those conflicts were not included in any administration analysis. Fourth, no incremental value-added was considered as a result of marketing organization operations when including the marketing organization cost in the economics.

The Administration decision to take gas-in-kind was not based upon MMS experience. The MMS experience was not used as the justification for a State in-kind program. In fact, the recent MMS decision to take Firm Transportation commitments was made after the administration decision to take gas-in-kind. Nevertheless, the MMS experience over the last several years, their internal review of that experience, as well as their decision to take "the next step" by entering into FT commitments is a reasonable data point worth considering as corroborating evidence that the administration's decision was reasonable.

The administration has stated repeatedly the reasons for taking State GIK: 1) improve producer economics thereby improving our opportunity to get a gas line, 2) eliminate valuation disputes, and 3) provide for in-state needs.

The fact is, that the administration included a high marketing organization cost in the Contract economics – a fact consistently ignored by critics. That cost – 5.5 cents/mcf exceeds any consultant estimates of gas marketing costs, and totals 16 million dollars per year. With this, and all other burdens and costs considered, at the bottom-line the Contract retains the state's full value of our state resource, compared to the "status quo" – plus we have reached an agreement which provides us the best opportunity available to get a pipeline built.

Standing alone, Mr. Griffin's comment that "MMS is entering a world very similar to our own" is an obvious overstatement. The statement was spoken, and intended, in the context of the current shift of MMS policy from exclusively using interruptible transportation to taking out firm transportation commitments. The similarity is that these Firm Transportation commitments are significant, they are forward-looking multi-year commitments with a significant financial liability attached to them, and by their nature they force MMS to relinquish their RIV-RIK switching opportunities for these gas volumes for the term of the contract.

The dissimilarities between the proposed State FT commitment and the MMS FT commitment are indeed significant. The MMS is committing only a small portion of their gas to FT; the remainder is shipped using interruptible arrangements on existing infrastructure and enjoys the benefits of RIV/RIK switching. By committing to taking our gas in-kind, the state will be obtain a gas line through

which to finally bring our gas to market. The MMS benefits from a 'portfolio' affect by having multiple gas supply points, and multiple transportation and sales contracts. The State needs to foster the commitment necessary to get the infrastructure built to move our stranded gas to market. The MMS has the luxury of incrementally building their RIK program, while benefiting from established RIV relationships and revenues. The State receives nothing for our gas until the infrastructure is built – but we also have the experience, time, opportunity, and access-to-expertise necessary to research, design, benchmark, staff and/or partner, and test our in-kind gas sales program. The MMS delivers approximately 500 million cubic feet per day in relatively small individual contracts to a variety of markets. The state will deliver 600 to 800 million cubic feet per day to one of the largest, most-liquid gas market hubs in North America, with the potential of reaching markets from New England to Oregon – a potentially leveraging opportunity for the state to manage risk and maximize value.

The July 24 memo is structured to imply that the MMS commitment to take firm transportation on the Rockies Express Pipeline is, essentially, not a true FT commitment: "The only FT commitment the MMS has ever made . . . provide MMS unique termination rights on 30 days' written notice". Frankly, the ability to terminate FT on 30 days' notice is not FT. The facts gleaned from review of the Rockies Express document are:

- The termination rights have been <u>requested</u> in the Rockies Express application to FERC. They have not been approved.
- The MMS request to terminate their FT commitments is constrained to a narrow window of policy changes or legislative action which would have the affect of removing MMS' authority to hold such commitments. The MMS did not request a blanket right to terminate FT. The MMS request does not extend to the right to terminate FT for economic or financial reasons.
- The MMS relies upon a 2005 FERC decision on an <u>interruptible</u> transportation case, in which FERC agreed that as an agency of the Federal government, MMS need not be bound by the laws of a particular state (113 FERC P 61,312 at P 5).
- The ultimate basis for the MMS request is a 2001 Columbia Gas Transmission Corporation decision (97 FERC P 61,221 at 62,004.). That decision states in part, concerning deviations from the standard terms of service agreements, that a material deviation can be approved by FERC where it "is negotiated with an individual shipper to address its unique characteristics, without affecting the quality of service received by that shipper or others." (Emphasis added)
- It is not clear that the MMS request cited in the July 24 memo will be considered by FERC to not 'affect the quality of service received by others'.

- The administration concluded this termination request was not relevant to informing the committee or to the committee's decision making, and chose to neglect such distractions in our original testimony.

Taking GIK is a major issue which must be, and which can be managed by the State. The risk to the state, however, should not be over-stated, particularly with respect to the risk of not getting a pipeline at all. Marketing of our own gas involves uncertainties. We have already started researching how the state will manage, resolve, and narrow those uncertainties. It is not a question of "if", but "how" these issues are best managed in the best interests of all Alaskans. The policies guiding those decisions are under the authority of the legislature to determine.

The financial commitments and management responsibilities assumed by the state are indeed huge – but they are normal business arrangements entered into by North American gas shippers on virtually all new gas pipelines. The market mechanisms and the market liquidity exist to manage the State's gas transportation and marketing needs.

Taking of our gas-in-kind and of fixed capacity commitments have been characterized as "revolutionary and precedent setting". The fact is that this entire project is precedent setting. This project is one of, if not the, largest single financial commitment undertaken by industry. That's using 4-year-old cost estimates, and this is at a time when international competition makes obtaining the steel and the labor needed to build this line serious concerns, each with the potential to adversely affect both cost and schedule to a tremendous degree.

For Alaska, the precedent setting feature here – the exciting, precedent setting opportunity – is that, for the first time, an agreement has been brought forward providing promise that the pipeline project can be completed. Toward that end, yes, the state has committed to use existing tools to participate as a shipper in the existing market systen.

Sincerely,

Michael L. Menge
Commissioner

cc: Senator Seekins

STATE OF ALASKA

DEPARTMENT OF REVENUE

OFFICE OF THE COMMISSIONER

FRANK H. MURKOWSKI, GOVERNOR

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September 20, 2006

Senator Gary Wilken
Alaska Senate
State Capitol Room 518
Juneau, AK 99801-1182

Dear Senator Wilken:

This letter is in response to your letter of August 18, 2006 concerning the proposed contract under the stranded gas development act.

In that letter, you recite the history of the 1973 special session that crafted the special Oil and Gas Production and Pipeline Properties property tax, essentially unamended from that time to this as Alaska Statute 43.56. However, you caution that

> even though members of the Eighth legislature crafted an even-handed tax bill, several events have occurred over the intervening years to skew the wealth to one area of the state.

Even assuming that your analysis is correct, all subsequent legislatures over the past 30 plus years have chosen not to amend AS 43.56 to redress the putative skewing of state wealth. At another point in your letter you discuss a "unique formula specifically approved for the borough" for calculating mill rates - but please remember that the formula was written into statute by the legislature and then subsequently upheld by the Alaska Supreme Court. While some years ago the Senate did pass a bill which would have affected the balance, it did not become law or overturn the 1973 rules. The legislature and the courts have spoken clearly and it is their guidance we must follow.

Accordingly, the instructions to the negotiating team were to preserve for the legislature *all those powers pertinent to dividing revenues between the state and political subdivisions currently reserved to the legislature.* The contract did just that. Your careful analysis of Exhibit G will have shown you that not a dollar is dispersed to a municipality by formula except where that formula includes the municipalities' mill rate over 20. (In article 18, the legislature will disperse 125 million or more dollars in impact funds directly to municipalities or through other ways of mitigating impacts.). If the legislature chooses to limit certain municipalities to a mill rate of ten under certain conditions, it may choose to. If the sole municipality so limited were the North Slope

Borough - as it was in prior the legislative attempt - then under the contract a significant amount of money will shift from that borough to the state.

I appreciate your offer to work together to craft a solution to what you characterize as a misallocation of our state's resources. But the contract leaves this as a matter for the legislature to decide - it need not play a role in our negotiations with the producers. In the contract we have preserved the flexibility so that if the state arrives at a solution different than current law, that solution will flow through to the contract.

The reason administration officials were directed to speak against your amendment 12 on August 8, 2006 was that we believed that its core idea - that "the method of distribution of payments received in lieu of taxes are not effective unless the methods are enacted by law"- was already true.

Very truly yours,

Bill Corbus

William A. Corbus
Commissioner

STATE OF ALASKA

DEPARTMENT OF REVENUE

OFFICE of the COMMISSIONER

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September 25, 2006

The Honorable Senator Gene Therriault
Chair
Legislative Budget & Audit Committee
3340 Badger Road, Suite 290
North Pole, AK 99795

The Honorable Representative Ralph Samuels
Vice-Chair
Legislative Budget & Audit Committee
716 West 4th Avenue, Suite 630
Anchorage, AK 99501-2133

Gentlemen:

Enclosed is the Murkowski Administration's point-by-point response to the Greenberg Traurig (legislative counsel) July 3, 2006 memorandum entitled "Follow-up from 'Round-Table' discussions on SGDA Contract". The Administration and our counsel, Morrison & Foerster LLP, would be happy to meet with you to discuss the attached at your convenience.

Very truly yours,

Bill Corbus

William A. Corbus

Commissioner

Enclosure

Copy to: Don Shepler, Esq.

The LLC Agreement is unlike the fiscal contract, which has significant tax terms that arguably require legislative approval. Therefore, it is not appropriate for the Administration, as a matter of comity or otherwise, to seek legislative approval of the LLC Agreement in template or final form. The Administration has expressly stated that it would not seek legislative approval, although it has agreed to submit the Mainline Entity LLC Agreement to the Legislature for its review and comment. The Administration is working hard to complete the LLC Agreement and looks forward to comments from the Legislature about it. Nonetheless, any requirement that a template of an LLC Agreement be approved by the Legislature would be forced on the Administration by the Legislature, which would create an even greater risk of a usurpation of power by the Legislature in violation of the principles behind the separation of powers doctrine. Further, unlike the fiscal contract which implicates the Legislature's taxing power, an LLC Agreement will not likely overlap with any legislative power or quintessential lawmaking responsibility. For these reasons, we believe that approval by the legislature of an LLC Agreement template would likely violate the separation of powers doctrine.

The Alaska Supreme Court has repeatedly recognized the Alaska separation of powers doctrine. *Wade v. Nolan*, 414 P.2d 689, 698 (Alaska 1966); *Public Defender Agency v. Superior Court*, 534 P.2d 947, 950 (Alaska 1975) (citations omitted). The court has noted that "the underlying rationale of the doctrine of separation of powers is the avoidance of tyrannical aggrandizement of power by a single branch of government through the mechanism of diffusion of governmental powers." *Bradner v. Hammond*, 553 P.2d 1 (Alaska 1976). Additionally, the Alaska Supreme Court has repeatedly observed that the Alaska Constitution creates a strong executive branch. *See Bradner*, 553 P.2d 1; Const. Conv. Min. Dec. 19, 1955, 42nd Day; Const. Conv. Min. January 13, 1956, 55th Day.

The negotiation and ratification of contracts falls within the power granted to the executive branch of government. The Alaska Superior Court has found that AS 37.05.280, a statute requiring legislative approval of state office space leases, "work[ed] an unconstitutional intrusion by the legislature into the sphere of the executive, violating the principles of separation of powers." *Marine View Chapter Juneau Tenants Ass'n v. Alaska State Housing* Authority, 1JU-80-1037 Civ., Nov. 3, 1981. Legislative approval of contracts has been held to violate the separation of powers doctrine in other jurisdictions as well. *See, e.g., In Re Opinion of the Justices*, 532 A.2d 195 (NH 1987) (citations omitted) (conclusion that legislative approval of contracts after appropriations are made to purchase or rent software is a violation of the separation of powers doctrine is similar to conclusions reached by numerous other jurisdictions); *Opinion of the Justices*, 892 So.2d 332 (Ala. 2004) (legislative veto of contracts entered into by the executive branch would violate separation of powers doctrine).

Impracticality

As you know, the project includes many facets other than the main pipeline to the Lower 48, including but not limited to a GTP. The GTP and/or other portions of the project may require a different form of agreement than what might be included in an LLC template designed for governance of the Mainline Entity which will own, manage and construct the pipeline to the Canadian border. Additionally, the Canadian portion of the pipeline may be built through a joint venture type of ownership structure which may require an agreement that looks very different from an LLC agreement template for the Mainline Entity. For example, such an agreement would not be governed by Delaware law but instead by Canadian national and provincial law.

For all of these reasons, approval of a template is impractical and will raise more questions than it will answer regarding aspects of the project whose governance structure has not yet been determined. Such a template may also inadvertently hamper the State's ability to choose the right management and ownership structure for other aspects of the project.

In sum, the Administration opposes legislative approval of an LLC template as an exhibit to the fiscal contract. The Alaska Permanent Fund Corporation currently invests billions of dollars in various assets without legislative approval of the form of agreement that it employs to make those investments. The agreements that will govern the various governing and management structures necessary for the gas pipeline should be similarly treated.

B. Choice of Law: Alaska versus Delaware

We are pleased that legislative counsel understands the significant benefits of the choice of Delaware law for the LLCs that will own the U.S. portions of the project. With over 50,000 Delaware LLCs in existence, Delaware is by far the most commonly chosen jurisdiction for entity formation within the United States, especially for complex and sophisticated commercial ventures. There are a variety of reasons commercial parties choose to form LLCs and other business entities under Delaware law, including (i) flexibility and freedom of contract, (ii) a broad body of case law, and (iii) judicial experience and expertise with respect to LLC, corporate governance and commercial disputes. Each of these factors contributes to a relatively high degree of predictability of outcome available under the Delaware LLC Act and case law. Sophisticated commercial parties, and potential lenders to the State, value this predictability of outcome because it mitigates the risk of litigation and other expenses and ensures that the parties have certainty with respect to their agreements regarding the governance of their venture. These

factors further the parties' objectives for the project and support the decision to establish the LLC under Delaware Law.

C. Level of Duty to LLC Members and Entity

In negotiating the issue of member "duties," the State team balanced the full range of considerations in order to advance both the State's commercial and governmental interests. Legislative counsel ask whether the State believes it or a producer is more likely to vote in its self-interest in a way that could be contrary to the interests of the LLC. After considering this issue in detail, including the "flip-side" of the producers voting in the same manner, the State LLC team concluded that the State member has as much, if not potentially more, to gain than the producers from the freedom to vote solely in its own interest.

While the primary interests of commercial LLC member entities, like the producers, are to maximize economic gain and protect competitive positions, the State will also likely have myriad other policy, political and social concerns that may be contrary to the commercial interest of the project entities themselves as well as the other members. The State may favor environmental protection measures, economic development priorities, equal protection, local social concerns and other objectives which may not necessarily serve the economic interests of the project entity. The State may also have different interests with respect to disputes between the LLC and third parties, where there may be policy reasons for opposing settlement or encouraging litigation of disputes between a project entity and third parties or the operator, even if there were differing views on what would be in the best economic interest of the project entity.

It should not be assumed that the State will be facing a unified producer bloc that functions as a de facto controlling member. While the producer members may jointly outvote

the State on some matters, the producers are not likely to be aligned against the State on all, or even most, issues. The producer group is comprised of competing companies with divergent interests. They frequently take fundamentally different positions on key issues. In fact, the most likely cleavage on voting issues may be between the operator/managing member and the other members, not the producer group and the State. The other producer members will certainly join the State in seeking to counter-balance the operator/managing member when appropriate and when there is a natural alignment of interests among non-operators in dealing with the operator/managing member.

We also note for the Legislature's information that the draft LLC Agreement does not provide that there will be no "duties" whatsoever among the members. The State expects that the managing member will have a duty to the other members to act as a reasonable and prudent manager of the LLC with due diligence and dispatch. This standard of care, as well as the limitations on member duties with respect to voting, is well established in the industry.

Legislative counsel suggest that "risk of claims against the State for acting in accord with its SGDA interests can be greatly reduced, if not eliminated" by expressly including SGDA requirements and specific provisions acknowledging the right of the State to act in its sovereign interests in the LLC governance agreement. While theoretically true, it would in practice be extremely difficult if not impossible to contractually address all of the potential areas where the State's interests may diverge from the interests of the LLC. As noted above, the State's interests are not limited to the identifiable requirements of the SGDA, but include a number of other policy concerns, such as environmental protection or broader economic development goals. It is simply not possible to identify all the specific areas of potential non-alignment of interest required to eliminate the risk of claims against the State for not acting in the interests of the LLC.

Instead, if the State took this approach in the context of a "higher duty to the entity" LLC, the only realistic contractual solution would be a broad carve-out from that higher duty allowing the State to act in its sovereign interests. Because almost any decision could be justified as being in the sovereign interest of the State, this broad carve-out would essentially eliminate a State duty owed to the entity, while requiring the other members to meet the higher standard. This is extremely unlikely to be acceptable to the other members.

Rather than creating two levels of duties for the State and the other members, the draft LLC Agreement protects the State by ensuring it has a vote on LLC actions where producer self-interest could have an adverse effect on the LLC or the State and by excluding members from voting on matters with respect to which they have a conflict of interest. The State is able to participate in discussions and vote its percentage interest on an equal basis as the other members – it is not a silent participant in the project entities. While the State, like the other members, may be out-voted with respect to certain matters, the LLC Agreement voting structure requires State approval for certain key actions.

D. Dispute Resolution/Venue

As suggested by legislative counsel, it is possible to create an LLC under the Delaware LLC Act where disputes are heard by the Alaska courts applying Delaware law. While this may address some of the political concerns with State involvement in a non-Alaskan LLC and issues of convenience, there are several advantages to hearing disputes in Delaware courts as opposed to an Alaskan court. Delaware courts have broader experience with LLC and commercial disputes than Alaska courts generally, and certainly have more experience applying Delaware law. While Alaskan courts may have greater experience with respect to oil and gas matters, disputes under the project entity agreements are likely to be commercial in nature and related to

corporate governance, not necessarily oil and gas-specific. Additionally, there are many oil and gas entities established in Delaware, and the Delaware courts are sufficiently experienced in adjudicating issues of oil and gas law.

Perhaps most significantly, Delaware courts offer a neutral ground for the hearing of disputes. There will likely be a perception of bias in favor of the State in any dispute involving the State being heard before the Alaska courts. This perception of bias may complicate and delay negotiations with the producers over the draft LLC Agreement, with lenders over project financing to the project, and with third parties with respect to other contracts needed for the project.

2. STATE CONSENT TO CHANGES TO QUALIFIED PROJECT PLAN

Legislative counsel continue to take the position that a contract provision should be added that requires the State's consent before any "material", "critical" or "essential" changes can be made to the Qualified Project Plan ("QPP"). July 3 Memo at 8, 10. In other words, counsel want the State to acquire veto power over changes to the QPP. Perhaps recognizing the one-sided nature of such a proposal, counsel go on to say that "[i]n fairness ... it would be reasonable to consider providing each of the Producers the same right to approve changes to essential QPP terms." July 3 Memo at 10.

Counsels' recommendation poses the obvious difficulty of defining contractually what would constitute a material change. Counsel suggest creating a list that would "easily remed[y]" the problem, one that would include "timing and scheduling changes, route changes (i.e. 'over the top'), and any significant capacity changes *and the like*." July 3 Memo at 8 (emphasis added). However, this suggested list does not remedy the problem. Is a scheduling change of

one month a material change? One year? How does one know when a change is a "significant capacity change" or a material change? Further, the words "and the like" could encompass anything. Counsels' breezy suggestion that a list of material changes can solve the problem is belied by their own suggested partial list which provides no contractually clear or helpful language, and, thus, fails to advance the ball.

More fundamentally, the State does not believe that it (or any producer) should have veto power over changes to the QPP. This project will not be built more rapidly by giving anyone the ability to unilaterally block a QPP change. The State is partnering with the producers to get this line built; it is not the producers' antagonist. Legislative counsels' veto power recommendation reflects a fundamental distrust of the producers' commitment to build the project in a timely manner. The State does not share that distrust and thus does not agree that additional contractual language of the type suggested is necessary or even desirable. The present language that allows for i) the State to initiate termination of the contract if the project has not progressed in a diligent manner, ii) the producers to cure any deficiency in a timely manner, and iii) actual termination if there has been a lack of diligence and a failure to cure, is sufficient.

The work commitments contained in the contract were crafted to ensure that the next stage of the project is started promptly, and that a disciplined, thorough project management process is implemented and maintained to control development and construction of the pipeline, ensuring the most cost-effective and timely project completion possible, and minimizing the risk to both the State and the producers. As a 20% owner of the Mainline LLC and a member of the LLC's management committee, the State through Alaska Pipe Co. will participate in the project planning and oversight of the operator that builds the pipeline. State ownership will provide Alaska Pipe Co. a continuing opportunity to know what is going on inside the project company,

be heard on key issues and influence the course of the project development. If, at any time, the State does not believe that the project is being advanced diligently, it can terminate the contract. The potential for terminating the very deal that the parties have spent three years negotiating is significant leverage over the producers, as the producers will lose all of the benefits of fiscal certainty if this contract is terminated by the State.

Finally, counsel acknowledge that "termination of the Contract would presumably be strongly resisted by the Producers." July 3 Memo at 9, fn. 3. Assuming that is true, then it can also be assumed that the producers would take advantage of the contract provision (Article 5.5(c)(iv)) that allows them to cure any deficiency so as to avoid termination.

3. EXPANSION COMMITMENTS

A. Expansion Is A Relevant Topic Even Before The Line Is Built

Legislative counsel discuss generally the issue of expansion and stress the importance of deliverability, i.e., the ability to deliver a particular volume of gas in a given period of time. However, counsel do not specifically criticize any contract provision, or lack of provision, other than to say that "it is also critical that the contract structure address expansion concerns for the near and mid range years of the contract." July 3 Memo at 10.

The State does not disagree about the importance of deliverability. While this contract, which is largely a fiscal contract and not a technical engineering contract, does not specifically address the topic of deliverability, it is widely understood and known that the *initial* design capacity of "approximately four (4) BCFD of Gas" (Article 4.1) can be expanded by adding compressor stations to achieve deliverability of approximately six (6) BCFD, and then be further expanded by looping. It is also well understood that if the open season bidding shows that the

initial design capacity is not sufficient, then needed compressor stations can be added to the design that will be submitted to the FERC as part of the certificate application so that there is sufficient initial capacity to serve all needs. Further, the approximately 50 percent flexibility (4 BCFD to 6 BCFD) for cheap, compression-based expansion without regard to looping should accommodate most foreseeable expansion needs for those near and mid range years of the contract. In the unlikely but fortunate circumstance that the maximum number of compressor stations still cannot serve the demand, looping can then undertaken.

A still further point should be made. The FERC open season regulations for the Alaska gas pipeline (Order 2005, 2005-A) stress the need to accommodate the needs of all shippers. As stated by FERC: "Our expectation is that an Alaska gas transportation project will be designed and built, to the extent possible, to accommodate all qualified shippers who are ready to sign firm transportation agreements." Order 2005-A at ¶ 34. For example, the FERC will consider how the project design considers the capacity needs of initial and future shippers. 18 CFR §157.36. As a further example, the regulations require that the Mainline LLC must even consider any bids tendered after the expiration of the open season by qualified bidders, and may reject them only if they cannot be accommodated due to economic, engineering or operational constraints. 18 CFR § 157.34(d)(2). Thus, FERC has an unprecedented regulatory role that should further alleviate counsels' concern about early expansion needs.

B. Commitments On Expansion And Rate Structure Do Not Intrude Upon FERC Authority

Legislative counsel in this and the following subsection argue that the contract or the LLC agreements should address the topics of expansion generally, and rate design (rolled-in vs. incremental pricing) in particular. July 3 Memo at 12-13. As noted in the next subsection, the

draft LLC Agreement does discuss the terms and conditions of expansions. Under that agreement, there can be both member-initiated expansion requests and requests made by potential shippers.

With regard to the issue of rolled vs. incremental pricing, neither the contract nor the draft LLC Agreement resolves that issue. It is no secret that the State and the producers have been unable to agree on this issue and have debated it publicly. Hence, the contract leaves the issue open for future resolution. However, Article 8.4 fully protects the State's right to intervene in any expansion proceeding and to argue for rolled-in pricing, and, therefore, the State will be able to get a full and fair hearing before the FERC. As counsel acknowledge, FERC will have the final word on the type of pricing. Hence, if the State's argument for rolled-in pricing convinces FERC, that will be the result regardless of what is said or not said in the contract. If it doesn't, then FERC will hold in favor of incremental pricing regardless of what is said or not said in the contract. It should also be recalled, of course, that FERC has created a presumption in favor of rolled-in pricing for expansions.

C. Contract is Silent On Voluntary Expansion

Legislative counsel are correct that the contract does not set forth the terms and conditions under which a voluntary expansion can be undertaken by the Mainline LLC. See July 3 Memo at 13-14. The reason is that those terms and conditions are a part of the not-yet-released draft LLC Agreement. That agreement will provide for a series of Management Committee votes to approve the various steps of an expansion, including authorization of a feasibility study, filing of a FERC certificate, and actual construction of the expansion. While Legislative counsel suggest that because of the delay in that agreement it makes sense to include those terms and

conditions in the contract, the State does not see any reason to add duplicative language to the contract, particularly given that the passage of time will render that suggestion moot.

D. Producer-Owned Pipeline Expansion Incentives Vs. Independently Owned Pipeline Incentives

Legislative counsel argue that an independent pipeline has a greater incentive to expand than does a producer owned pipeline. July 3 Memo at 14. Hence, they say that the contract should contain commitments to i) allow Contributions in Aid of Construction (CIAC), and ii) expand in reasonable engineering increments upon request by creditworthy shippers.

As discussed in more detail in 3F on the subject of sole risk, the combination of the voluntary expansion provision in the draft LLC Agreement, state initiated expansion in the fiscal contract and the mandatory expansion provision in ANGPA provide the State and shippers with adequate expansion rights. All expansions will be done in reasonable engineering increments, so there is no need for the contract language to say so. With regard to CIAC, the State did look at this concept in the same way that it looked at the sole risk concept. It ultimately chose not to press for this concept because the mandatory expansion provision of ANGPA serves as a sufficient backstop.

E. No Express Commitment To Seek Rolled-In Pricing

Legislative counsels' pitch for rolled-in pricing for all expansions is a repeat of their argument in 3B above. The State's answer in that subsection applies equally here.

F. Sole Risk Expansion

Legislative counsel are correct that the State did consider including a sole risk expansion provision in the contract. See July 3 Memo at 16-17. In the end, however, the State determined

that the mandatory expansion language of the ANGPA provided a sufficient basis for the State, or an independent explorer, to force an expansion even if the Mainline LLC was opposed to it. During the negotiations over a sole risk provision, the expansion conditions set forth in Section 105 of the ANGPA became both a floor and a ceiling. It became unrealistic to expect the producers to agree to sole risk expansion conditions that were more favorable to expansion than the conditions contained in Section 105. The State views Section 105 as a significant, positive tool to promote needed expansions. Negotiations for a sole risk expansion provision (as well as a CIAC provision) were unable to secure a better tool and, hence, were ended.

G. The "State-Initiated Expansion" Provision Provides Little Assurance Of Timely Expansion

Legislative counsel contend that the State-initiated expansion provision (Article 8.7) offers little if any value because it is more restrictive than the mandatory expansion language contained in ANGPA. July 3 Memo at 17-18. Anadarko has publicly taken a similar position.

The intent of Article 8.7 was to add a third avenue for expansion—one that might offer a faster way to achieve expansion. The State continues to believe that Article 8.7 could enlarge the expansion options in a beneficial way but recognizes that others appear to be reaching a different conclusion. The State is in the process of gathering reactions from various independent producers -- the entities Article 8.7 is meant to help. If the feedback is similar to that expressed by Anadarko and legislative counsel, the State will consider seriously the option of dropping Article 8.7 from the contract.

4. RCA JURISDICTION

Legislative counsel raise several points regarding the RCA. First, they suggest that there may be gaps in the FERC's jurisdiction over project facilities. They further suggest that there is

a possibility that FERC will decline to regulate the GTP and some of the gas transmission pipelines upstream from the GTP. Assuming there is a gap in FERC regulation and the RCA steps in, counsel are concerned about the contract provision that requires "the State to reimburse any of the Producers' losses accruing through RCA orders." July 3 Memo at 19. Counsel state that it is a legislative policy call "as to whether the State should reimburse overcharges if determined by the RCA." July 3 Memo at 20. Finally, counsel claim that it is not entirely clear that the State would not have to reimburse the producers for lost profits arising from an RCA-ordered refund. July 3 Memo at 20.

Taking the last point first, the State believes the contract language is clear and sufficient. Article 37.2 says, in relevant part, that "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*...." (emphasis added). Article 8.3, in turn, provides that if, under certain circumstances, the RCA causes a Loss to a participant, "the State shall reimburse that Participant for the Loss...." Taken together, these two provisions mean that while the State may have to reimburse a participant for an RCA-caused Loss, the reimbursement will not include lost profits. Hence, if hypothetically, the RCA were to reduce the rate of return on equity on a RCA-regulated project facility in a way that was inconsistent with FERC's approach to the same issue, that would be a reduction in profit and therefore not subject to reimbursement by the State.

The State agrees with counsel that it is a legislative policy call as to whether the State should reimburse the participant's for an RCA-caused Loss under the conditions set forth in Article 8.3. That is why not only Article 8.3, but the whole contract, is before the Legislature for approval.

With regard to the scope of RCA jurisdiction, neither the State nor the producers envision RCA rate regulation of any project facilities. It is essentially certain for several reasons that FERC will regulate the $2 billion plus GTP. First, in its open season regulations for the Alaska gas pipeline, FERC made clear that the gas treatment service and the transportation service must be unbundled and offered separately in an open season. Order 2005-A at ¶¶ 87-88. Were FERC not contemplating regulating the GTP, it would not have made such a statement.

Second, FERC's general jurisdictional test is whether a treatment plant is used primarily to render raw gas fit for transmission or to extract liquids and liquefiables for their economic value. *Venice Gathering Co.*, 97 FERC ¶ 61,045 (2001); *Columbia Gas Transmission Corp.*, 79 FERC ¶ 61,041 (1997). Plants that are used to treat or condition gas to bring it up to pipeline quality so that it can be transported safely and efficiently are classified as jurisdictional transportation facilities, while plants that operate principally to extract liquids and liquefiables for their economic value (*i.e.*, gas processing plants) are classified as non-jurisdictional facilities. 79 FERC at 61,185. *Northern Natural Gas Co.*, 69 FERC ¶ 61,264, at 62,016-17 (1994); *Texas Eastern Transmission Corp.*, 43 FERC ¶ 61,044, at 61,129 (1988). The GTP will be a plant that will be used to treat or condition gas to bring it up to pipeline quality, and thus a jurisdictional facility subject to FERC's regulation.

Third, the Alaska Natural Gas Pipeline Act, Section 102(2), defines the term "Alaska natural gas transportation project" as "any natural gas pipeline system that carries Alaska natural gas to the border between Alaska and Canada (including related facilities subject to the jurisdiction of the Commission)...." And, while President Carter's 1997 Decision selecting the Alaska Highway route defined the Alaska Natural Gas Transportation System ("ANGTS") as beginning at the discharge side of the conditioning plant facilities, in 1981 then-President Reagan

signed six waivers of law, one of which included the conditioning plant within the ANGTS. The Administration synopsis accompanying the waivers said that "[a]s a practical matter, the economic effect of including the conditioning plant in the system is the same as treating the plant as a separately certificated facility and providing a conditioning cost allowance sufficient to provide for the recovery of the gas conditioning cost." Report of the Senate Committee on Energy and Natural Resources November 10, 1981, at 33 (No. 97-272, 97th Congress, 1st Session.

With regard to gas transmission lines that will feed into the GTP or the Mainline, counsel are correct that the definition of non-jurisdictional gathering lines versus jurisdictional transmission lines has turned on an examination of various physical and operational factors, which have changed over time. July 3 Memo at 19. Because several of these lines are neither designed nor built, one cannot say with certainty that they will be FERC-regulated. The parties contemplate that those parties qualify as jurisdictional transmission li . If they do not, nothing in the contract bars the RCA from regulating those lines if it has the power to do so under its jurisdictional statutes[1]. All the contract does is create a limited right of indemnification in certain circumstances, excluding lost profits, if those lines are regulated in a manner contrary to FERC regulation or commercial principles. The State believes that this possibility is remote and its exposure is quite limited.

CAPACITY MANAGEMENT IS CRITICAL AND COMPLEX

Legislative counsel expressly do not take issue with the terms of the capacity management provisions in the contract (Article 10) and, indeed, acknowledge that "the

[1] Legislative counsel do not provide any analysis of whether and when the RCA has jurisdiction over gathering lines; they simply assume that it does.

Administration and the Producers have addressed many, if not all, of the concerns." July 3 Memo at 20, 23. Rather, they stress the complex nature of capacity management and state that the "real question to the Legislature is whether these terms completely assure the State that its gas and its capacity will at all times (i.e., as frequently as every 8-hours) be perfectly balanced with no 'ullage' to drain value from the State's gas or capacity." July 3 Memo at 23.

The State submits that counsel have framed the question incorrectly. The producers have no assurance that their gas and their capacity will at all times be perfectly balanced, with no ullage to drain value from their gas or capacity. The fact is that the producers and the State are at risk that capacity and gas will not be balanced. That risk simply cannot be eliminated. While the capacity provisions in the contract can not eliminate that risk, they can and do assure that the State and the producers share that risk proportionate to their capacity ownership percentage. Hence, if that State has a 20% capacity ownership percentage and the pipeline has 100 units of excess capacity, the State's share of that excess will not exceed 20 units. Thus, the proper question to ask is: Are the risks proportionate among the State and the producers? The answer is yes.

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Senator Thomas H. Wagoner
145 Main Street Loop; Suite 226
Kenai, AK 99611

September 27, 2006

Dear Senator Wagoner:

This is in response to your July 21, July 25 and August 7 letters regarding the Alaska Stranded Gas Contract. We apologize that we did not respond your letters sooner, and thank you for your patience.

Fiscal certainty on oil and gas taxes

Fiscal recognized certainty on a $20 billion plus gas pipeline project is critical to the commercial viability of the project as the Alaska Stranded Gas Development Act recognized.

On two separate occasions the Alaska Legislature spoke to the subject of the term of a fiscal contract. On both occasions the legislature clearly indicated that a fiscal contract could be developed for a term of 35 years from commencement of commercial operations. In 1998, the House passed the SGDA bill with 35 votes in favor and the Senate had 20 votes in favor. The legislature sent an even clearer message in 2003 when reauthorizing the SGDA. The House unanimously passed the reauthorization and the Senate had 19 votes in favor, with one party excused. Thus, the legislature correctly anticipated in 1998 and again in 2003 that a project of this magnitude would require a 35 year term starting at commencement of commercial operations.

Thirty-five years of fiscal certainty during production is not uncommon in large oil and gas related projects. The State's consultant, Dr. Pedro Van Meurs, analyzed a number of international agreements. Based upon his data, it is clear that many countries offer contracts for fiscal stability that include 30 years or more of production. In fact, a recently completed multi-billion dollar Caspian Basin pipeline project provides a fiscal stability term of 60 years. In many cases, at the end of the primary term of those agreements, there is an extension if the asset is still producing. International precedent not only includes extensions for continued production, but there is precedent for "life of field" terms for gas. Prudhoe Bay Unit alone will likely be producing gas for at least 35 years from first gas, depending on the off-take rate established by the PBU owners and the AOGCC.

Nevertheless, the length of fiscal certainty proposed in the contract has been one of the most hotly debated contract issues and several legislative amendments to scale back the length of those terms in the contract have been offered. The Administration heard this concern during the

public process from the general public and the legislature and is prepared to renegotiate this provision of the contract.

A State LLC to market and sell Alaska Gas

The Alaska Gas Pipeline Company, LLC (the LLC), which will own the mainline, is different from the Alaska Natural Gas Marketing Company (ANGMC), which will market and sell Alaska Gas, and from the Alaska Natural Gas Pipeline Corporation (ANGPC), which will own the state's 20% membership interest in the LLC. The state and the sponsor group will jointly own the LLC through other entities (i.e. ANGPC, etc.) to be formed. The LLC will operate under the Delaware laws. Delaware law was selected because of its flexibility and freedom of contract, a broad body of case law, judicial experience and expertise with respect to LLC, corporate governance and commercial disputes. Each of these factors contributes to a relatively high degree of predictability of outcome available under the Delaware LLC Act and case law. Sophisticated commercial parties, and potential lenders to the State, value this predictability of outcome because it mitigates the risk of litigation and other expenses and ensures that the parties have certainty with respect to their agreements regarding the governance of their venture. These factors further the parties' objectives for the project and support the decision to establish the LLC under Delaware Law.

Specifics of organizations of the ANGMC and the ANGPC are still uncertain, as a wide variety of marketing, business, tax and other issues must be worked out. These two organizations, however, will be entirely within the authority of the state and will be owned by the state. They will operate under the Alaska laws and will not be LLCs. A number of successful templates for organizations of the ANGMC and the ANGPC exist within the state include: the Permanent Fund Corporation, the Alaska Railroad Corporation, the Alaska Industry Development Export Authority and the Alaska Housing Finance Corporation.

Capacity expansion and access to the pipeline capacity

Most of the concerns expressed by explorers about pipeline expansion had to do with the terms of Article 8.7, which was intended to apply only to State-initiated expansions. These terms were not intended to affect voluntary expansions (the terms of which are contained in the LLC agreements) or mandatory expansions (under FERC authority). Both the sponsor group and the explorers seemed to prefer to rely upon FERC mandatory expansion authorities, rather than accept the provisions of Article 8.7. Based on explorer input, the administration proposes to delete Article 8.7, and rely upon the LLC voluntary expansion provisions and the FERC mandatory expansion authorities to ensure appropriate pipeline expansions occur.

Expandability of design must be balanced against the costs and risks of creating that flexibility. Clearly, the most difficult and risky increment of capacity to obtain is the initial increment -- construction of the initial pipeline system itself. Because no gas pipeline or gas pipeline contract

exists, no players are entering the Alaska market today. Completion of a gas pipeline contract and completion of the initial pipeline system can only increase the confidence of new players that they can find markets for their gas discoveries. This is particularly true, given FERC's authority to require that expandability be designed into the pipeline, and to mandate that expansions occur. It must be remembered that reserves have not yet been proven-up to fill the pipeline throughout its initial term. It must also be remembered that the greatest risk to the state is not getting a gas pipeline to get Alaskan gas to market before the opportunity passes.

Current Leases

Article 41.2 states that ". . . any right, privilege, or obligation of a Party in a lease, other agreement, regulation, rule, order or decision is amended for the Term only to the extent necessary to conform with the provisions of this Contract. . ." Other terms of those leases, unit agreements, or other documents are not affected by the contract. The language, 'only to the extent necessary to conform' was explicitly included to limit the scope of this provision. The sponsor group was concerned that other agreements, regulations or decisions could be used to undermine commitments made within this contract. If the contract terminates, due to lack of diligence or for any other reason, this provision also terminates.

State of Alaska concessions or subsidy of the gas pipeline

In your August 7 letter you suggested that the proposed contract contained $15 billion dollars in concessions to industry. Because the administration has often insisted that the contract produces the same benefits to the state as the status quo, you asked for the list of offsetting $15 billion in industry concessions.

Table 6 on page 73 of the Preliminary Fiscal Interest Finding (reproduced on the next page) compares State take under both existing rules and the proposed contract for oil and gas. State take are presented in nominal and real terms and for a range of gas prices from $3.5 per mmbtu to $8.50 per mmbtu.

When discounted, at 6% and 8% discount rates, for gas the status quo shows a slightly higher figure than the contract, though nowhere near the size your analysis suggests. Furthermore, the contract always produces more value at higher prices when oil is taken into account (and the analysis presented was with a 20% PPT and no progressivity). This is important because several of the effects you listed are really effects from the PPT or were modeled as PPT effects for the Preliminary Fiscal Interest Finding.

Essentially the contract reforms the state's take, so that it gets its cash flow in different ways than under the status quo. Thus at most prices the take is essentially identical. We expect prices over the next decades to demonstrate the same level of volatility as they have over the past decades.

Therefore, one of the adjustments we made was to take more oil revenue at high prices and less revenue at low prices (as can be seen from the table). So to address your question – our willingness to take less revenue at low prices versus the offset by increased take at high prices.

Table 6. Comparison of Total State Oil and Gas Revenues

	Revenues of Project Under 2005 Fiscal System			Revenues of Project Under Proposed Contract		
	2005 Oil	2005 Gas	Total	PPT Oil	SGDA Gas	Total
Price Level/Results	Revenues ($ Billions)			Revenues ($ Billions)		
$3.50 per mmBtu of Natural Gas at Chicago City Gate/$22 per barrel of WTI Crude Oil						
Nominal $						
Total (2007-2050)	33	57	90	29	57	86
Present value (at 8%)	11	8	19	9	7	16
Real $ (2005)						
Total (2007-2050)	20	28	48	17	28	45
Present value (at 6%)	10	7	17	8	6	14
$5.50 per mmBtu of Natural Gas at Chicago City Gate/$35 per barrel of WTI Crude Oil						
Nominal $						
Total (2007-2050)	66	101	167	71	101	172
Present value (at 8%)	22	14	36	24	13	37
Real $ (2005)						
Total (2007-2050)	42	52	94	46	52	98
Present value (at 6%)	21	13	34	23	12	35
$8.50 per mmBtu of Natural Gas at Chicago City Gate/$55 per barrel of WTI Crude Oil						
Nominal $						
Total (2007-2050)	111	167	278	158	167	325
Present value (at 8%)	37	24	61	52	23	75
Real $ (2005)						
Total (2007-2050)	73	90	163	96	90	186
Present value (at 6%)	35	22	57	46	21	67

Source: ADOR model.

Notes: Total revenues are expressed in billions of both nominal and real dollars over the period 2007 to 2050.

The estimates above are based on the following assumptions:

1. PPT provisions are per the House Finance Committee substitute for Senate Bill 305 as of midnight on May 7, 2006.
2. Revenues for the gas proposal are net of all state expenses, including investment and the 20 percent investment credit.
3. Revenue streams include total state revenues including royalties, severance tax, property tax, and corporate income tax.
4. The property tax numbers do not include TAPS.
5. Debt from state investment is retired by the end of 2035 (20-year debt).
6. Ability to tax facility and equipment exists before gas pipeline is built.
7. SGDA gas includes earnings from ownership of the gas.
8. Assumes an Alaska to Alberta project.

Let us address each the concessions you cite in your July 21 letter:

> $5.45 billion in new costs allowances: You correctly observe that with an inflation rate of 3.5%, the cost allowance figure will be large. But please note that high inflation will also yield much more in the PILTs that replace the property taxes. Rapidly inflating PILT figures will generate much more than depreciating cost base assessments.
>
> $4.0 billion upstream tax credits: Your $4.0 billion figure is dependent on a $10 billion investment. In the last several years the Producers have been investing about $1.5 billion per year (Note: this is for oil and gas). So we do not believe that there will be $10 billion in new gas-specific upstream investment. But, if there is, then under the PPT, that would generate deductions and credits of something greater than 42.5%, depending on progressivity. If in fact, the PPT and contract totally change the North Slope investment figure to get $10 billion in upstream incremental investment, then they will have done their job.
>
> $1.96 billion in midstream pipeline and GTP credit: This was recast as the commitment credit in the final contract, there is no exact analog to those payments in the status quo, but they will offset other commercial payments or higher take in the contract payments.
>
> $0.46 billion processing subsidy: We do not know how the CO2 will be handled, so it his hard to attach a price to it. But if your assumptions are right, those charges would come out to about $14 million dollars a year, not $460 million.
>
> $1.4 million marketing subsidy: (This should be $1.4 billion.) Again, this was part of our comparison, based on 5.5 cents per mcf. There is no exact analog to those payments in the status quo, but they will offset other commercial payments or higher take in the contract payments.

If one believes that despite the evidence of the last quarter century a gas pipeline is wildly economic, one will also believe that the state was not as assertive at extracting rents from the project as it ought to have been.

If however one believes, as I and the team of experts, both within and from without the state government do, that the project is one that carries large risks and may not appear as likely to be built when compared with industry investments around the word, then our negotiations were more than just dividing up the project's economic rents. We were attempting to create an environment in which such a project would be more likely to be undertaken. We succeeded. In the end concern about what the Producers get instead of getting a pipeline for the state will lead to the greatest risk to Alaska – not getting a gas line at all.

Under the status quo the breakdown of revenue for gas at $5.50 per mmbtu is as follows:

Royalties	$53
Severance Tax	$27
Property Tax	$ 7
State Corporate Income Tax	$14
Total	$101

Under the contract the breakdown of revenues is as follows:

Revenues		
Gas sales	$93	
Tariff income	$ 3	
Various PILT's	$ 7	
State Corporate Income Tax	$14	
Total		$117
Costs		
Principal and interest	$7	
Operating costs	$3	
Marketing costs	$1	
Upstream cost allowance	$4	
Taxes	$1	
Total		$16
Net Income		$101

The producer considerations mainly manifest themselves in the higher severance tax rate and pipeline income.

Note too that the new oil PPT can be considered a direct result of the negotiating process. In that regard, at $60 oil, the oil production tax will be $86 billion higher than under the old status quo through 2050, a six-fold increase.

Ownership of the GTP – 35% vs. 20%

The proposal for the State to own a portion of the pipeline stemmed from the proposal to take about 20% of our gas in-kind.

The purpose of taking the gas in-kind was to increase the producers' rate of return; under the in-value system the producers pay for 100% of the pipeline but only get 80% of the gas. If we took the gas in-kind but did not own any of the pipeline, the State would make a firm transportation

(FT) commitment to the pipeline owners (producers) guaranteeing we would pay to ship our gas no matter what. This commitment is an asset to the producers that financially offsets the cost of building the share of the pipeline that carries the State's capacity.

Going to ownership itself was only a small step, and gave the State additional benefits, like pipeline income and a seat at the table.

The State's ownership in the GTP could have been greater than, less than, or equal to its capacity. If it was less than its capacity, again, we would have had to make an FT commitment to cover the difference. If it was greater than its capacity, the producers would have had to make an FT commitment to us for the difference. Either way, the financial result will be an ownership share that approximates the capacity share.

The purpose of the GTP credits was to provide an additional incentive to build the gas line.

Trigger price for monetary concessions

Many of the changes in the fiscal contract represent structural changes over the life of the project (including construction) and represent risk/reward sharing at high and low prices. It would not be possible to adjust all the elements of the structure with the vagaries of price; moreover, the risk/reward balance would be materially altered.

Conclusion

You have expressed your concerns and views regarding the period of fiscal certainty, the LLC, capacity expansion, nullifying the existing terms of the gas leases, State concessions, GTP ownership and a tax liability floor for gas. For the period of fiscal certainty and capacity expansion we have indicated intent to renegotiate the contract to address your concerns. The Administration has explained its views regarding the LLC that the terms of the existing gas leases are generally protected and that the contract does in fact provide a floor for low priced gas. We have shown, by comparing with the Status Quo, that the concessions made in various provisions of the contract (including the GTP) are offset by increased revenues elsewhere. We have demonstrated that the incentives and producer payments create a balance that we think is more likely than not to create an environment in which the gas pipeline is likely to be built. In the end concern about what the Producers get instead of getting a pipeline for the state will lead to the greatest risk to Alaska – not getting a gas line at all.

Very truly yours,

Bill Corbus

William A. Corbus
Commissioner

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October 18, 2006

Mr. Tom Irwin
758 Illinois Street
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Fairbanks, AK 99707-1249

Dear Mr. Irwin:

This is the State of Alaska's (State) Reply to the July 24, 2006, comments of Tom Irwin, former Commissioner of Natural Resources (DNR), Marty Rutherford, former Deputy Commissioner of Natural Resources and four other former Department of Natural Resources officials. We will respond to the comments generally in the sequence the comments were made.

Our letter will address the substantive points raised by the July 24, 2006, comments of the former DNR team. In answering those comments, we also address the substance of the separate July 20, 2006, comments of Mr. Richard LeFebvre, who also signed the July 24, 2006, comments. We note that Mr. LeFebvre's comments make the same points as the July 24, 2006 comments, in the same sequence and with almost identical language.

Enclosed as Appendix I is an analysis of how some of the comments made in the July 24, 2006, letter are in serious conflict with the positions that the former DNR team asserted in the negotiations which it led with TransCanada and with the positions the former DNR team supported as the State was preparing to begin negotiations with the North Slope Producers.

There is a misconception that runs throughout the comments. The point of the Stranded Gas Development Act SGDA is to secure a fiscal contract on the gas resource. That is a contract that establishes a framework of fiscal certainty on the tax on gas that is designed to underpin the firm transportation (FT) commitments necessary to facilitate the financing of a gas project.

The SGDA's purpose is to (1) "encourage new investment to development the State's stranded gas resources by authorizing establishment of fiscal terms relating to that new investment," (2) "allow the fiscal terms 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." AS 43.82.010. (Emphasis supplied.) The statutory purpose was not to secure negotiation of a contract just to build a gas pipeline. Securing a contract for that midstream element alone will follow in due course once the financing based on the FT commitments is in place. Rather, the point of the fiscal contract is to establish the fiscal terms that would bring about development of the entire gas project and that

necessarily included both midstream and upstream elements.[1] The proposed Fiscal Contract achieves the statutory purpose.

The opening paragraph of your comments argues that "the SGDA Fiscal Interest Finding and Determination, and the proposed SGDA contract is (sic) fundamentally flawed." The asserted flaws generally concern the analysis of alternatives, the impact of the fiscal contract on the State's budget and cash flow, and whether the gas is stranded. It is asserted that the Finding is premature and the public process flawed because the proposed SGDA fiscal contract is not final or complete. Finally, you assert that the fiscal contract was negotiated outside the parameters of the SGDA and thus the process was not lawful, transparent nor fair to other SGDA applicants. Not one of these conclusions is backed up by analysis or a factual foundation. Each is incorrect.

First, the preliminary Fiscal Interest Finding (the "PFIF") contains the specific information required to satisfy Section 43.82.400 of the SGDA. As required, the PFIF compares the projected public revenue from the project with estimated operating and capital costs of additional State services and the "reasonably foreseeable effects of the proposed contract on the public revenue." PFIF at 73-78, 80. As required, it describes the principal factors why the proposed fiscal contract is in the public interest, including the projected price and production rate or volume of gas, the projected costs of the project and much other relevant economic material. PFIF at 241-253, 73-78, 80, 178-179. As required, it also contains an analysis of why North Slope gas remains stranded. 242-243, Appendix C. These are the requirements of the SGDA, and they are different than your description of what must be addressed. The fact that you disagree with the conclusions or analysis or want other things analyzed does not demonstrate the appropriate analysis was not undertaken. In fact, it was.

Second, the PFIF does contain a description of alternatives. See PFIF at 179-188. Because of the requirements of Section 43.82.310 regarding confidentiality, the description could not disclose specifics of the negotiations but, as you know, those details, if made public, would not support the sweeping generalizations you make about alternatives. Suffice it to say, no other alternative presented to the State came from parties that today have access to the gas that is essential to advance the project. As is apparent from the Port Authority litigation with ExxonMobil and BP, litigation with the Producers will be necessary for third parties to acquire the gas.

Third, your assertion that the public process is "premature" because the fiscal contract is neither complete nor final is off base. Your comments fail to specify what fiscal term is missing from the contract. The May 24 contract, a 457-page document with exhibits, completely captures every financial or fiscal element required for SGDA review. The fact that changes to the fiscal contract may result from the public process, and occur after it, does not justify delaying the public process. In fact, the SGDA contemplates that changes may result from the public

[1] That is one reason, for example, that the MidAmerican proposal was at best half a solution.

process. See 43.82.430 (the Commissioner of Revenue "shall. . . prepare a list of proposed amendments, if any, to the proposed fiscal contract that the Commissioner of Revenue determines are necessary to respond to public comments.")

Fourth, your letter repeats an argument you raised in October 2005 suggesting that the negotiations were unlawful or unfair to other applicants because the negotiations proceeded beyond the parameters of the SGDA. That argument was answered completely by the Attorney General in his letter to former Commissioner of Natural Resources Tom Irwin dated October 27, 2005, and we refer you to it. The administration was in frequent contact with the leadership of the Legislature about the progress of negotiations and was urged to seek the commercial contract terms that best promised early development of a gas pipeline. The SGDA was intended to guide the Administration in the negotiation of a gas contract with the expectation that the Legislature would review and authorize the final fiscal contract. Thus, the SGDA's purpose has been fulfilled. The very fact that the SGDA contemplates that the Commissioner of Revenue may propose contract changes after the public process, but before legislative authorization, shows that the SGDA contemplates a dynamic negotiation process, not one frozen by the scope of the initial applications under the SGDA or even the contract first negotiated by the Executive Branch.

In fact, there was no prejudice to applicants. In addition to the Producers, both Mid-America and TransCanada submitted proposals that went beyond your restrictive interpretation of what is permissible under the SGDA. Neither Mid-America nor Enbridge completed the process necessary to begin SGDA negotiations: neither had access to the gas. See PFIF at 188. The Port Authority also did not complete the qualifying round. PFIF at 18. Finally, by letter of July 13, 2006, TransCanada lent its support to the proposed fiscal contract as advancing the prospects of an Alaska gas pipeline. All of this suggests that no one was, in fact, disadvantaged by the process that was followed. Simply put, the purpose of the SGDA was to negotiate a fiscal contract on the gas and none of the non-producers had access to the gas.

Your complaint about the absence of transparency of contract negotiations is ill-founded. The negotiations advanced in conformity with Section 43.82.310 of the SGDA, which authorizes confidential treatment of trade secrets and commercial and competitive information. TransCanada and the Producers both requested and received confidential treatment of information they supplied in the negotiations. Accordingly, the details of negotiations with TransCanada and the Sponsor Group were, and remain, confidential. As the SGDA recognizes, it is standard commercial practice to negotiate business deals confidentially. The State simply could not, in good faith, nor consistent with the terms of the SGDA, negotiate with any SGDA applicants using confidential information, and then reveal that information.

When negotiations were concluded, however, the State immediately published the fiscal contract and a multitude of relevant documents. The State also arranged for extensive public education on the contents of the fiscal contract, both on the internet and through numerous public hearings throughout the State. Thus, the negotiations were conducted in such a way as to protect the legitimate commercial concerns of all applicants. But the fiscal contract will not be

CORRECTION

THE FOLLOWING DOCUMENT(S)
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ASSURE LEGIBILITY OR PAGINATION

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Fourth, your letter repeats an argument you raised in October 2005 suggesting that the negotiations were unlawful or unfair to other applicants because the negotiations proceeded beyond the parameters of the SGDA. That argument was answered completely by the Attorney General in his letter to former Commissioner of Natural Resources Tom Irwin dated October 27, 2005, and we refer you to it. The administration was in frequent contact with the leadership of the Legislature about the progress of negotiations and was urged to seek the commercial contract terms that best promised early development of a gas pipeline. The SGDA was intended to guide the Administration in the negotiation of a gas contract with the expectation that the Legislature would review and authorize the final fiscal contract. Thus, the SGDA's purpose has been fulfilled. The very fact that the SGDA contemplates that the Commissioner of Revenue may propose contract changes after the public process, but before legislative authorization, shows that the SGDA contemplates a dynamic negotiation process, not one frozen by the scope of the initial applications under the SGDA or even the contract first negotiated by the Executive Branch.

In fact, there was no prejudice to applicants. In addition to the Producers, both Mid-America and TransCanada submitted proposals that went beyond your restrictive interpretation of what is permissible under the SGDA. Neither Mid-America nor Enbridge completed the process necessary to begin SGDA negotiations: neither had access to the gas. See PFIF at 188. The Port Authority also did not complete the qualifying round. PFIF at 18. Finally, by letter of July 13, 2006, TransCanada lent its support to the proposed fiscal contract as advancing the prospects of an Alaska gas pipeline. All of this suggests that no one was, in fact, disadvantaged by the process that was followed. Simply put, the purpose of the SGDA was to negotiate a fiscal contract on the gas and none of the non-producers had access to the gas.

Your complaint about the absence of transparency of contract negotiations is ill-founded. The negotiations advanced in conformity with Section 43.82.310 of the SGDA, which authorizes confidential treatment of trade secrets and commercial and competitive information. TransCanada and the Producers both requested and received confidential treatment of information they supplied in the negotiations. Accordingly, the details of negotiations with TransCanada and the Sponsor Group were, and remain, confidential. As the SGDA recognizes, it is standard commercial practice to negotiate business deals confidentially. The State simply could not, in good faith, nor consistent with the terms of the SGDA, negotiate with any SGDA applicants using confidential information, and then reveal that information.

When negotiations were concluded, however, the State immediately published the fiscal contract and a multitude of relevant documents. The State also arranged for extensive public education on the contents of the fiscal contract, both on the internet and through numerous public hearings throughout the State. Thus, the negotiations were conducted in such a way as to protect the legitimate commercial concerns of all applicants. But the fiscal contract will not be

authorized until it is fully discussed and analyzed by the public and the Alaska Legislature. There is no valid complaint about transparency.

1. The Contract Does Not Guarantee a Pipeline and the Due Diligence Standard in the Work Commitments Clause is Weak. The work commitments under the fiscal contract are stronger than comparable large projects as the PFIF explains. PFIF 128-129. In contrast, you assert that the work commitments are weak but do not back up your assertion with any example of stronger work commitments or any work commitments at all from a real world project, let alone any mega-project. As is explained in the PFIF, there is not a single large multi-billion dollar international contract involving upstream and midstream elements that "guarantees a project," because a schedule-driven construction project will most certainly result in significant cost overruns. Such a schedule-driven construction project would increase economic risk to the owners and thus make actual construction of the gas pipeline less likely and more costly.

As former Commissioner Irwin would know from his own experience in mining, no major mining company would guarantee the completion before the permitting was undertaken and completed. The history of the Fort Knox mine, in which you participated, demonstrates this. No one can guarantee that economic, legal, and logistical conditions will not change during the execution of a long lead time mega-project to a degree that would make further investment in the project unattractive for any Sponsor or even the State. Finally, we noted former Commissioner Irwin's August 4, 2005, letter to Governor Murkowski regarding the State's position on negotiations made no mention of any issue with the work commitments clause or its diligence standard, even though the clause had been essentially negotiated at that time

The diligence standard to which you object contains core elements of the prudent operator standard applicable to leases, such as the concept of requiring prudent action by the Producers. The prudent operator standard must be read in the context of the Federal Energy Regulatory Commission (FERC) pre-filing and application process. This process is systematic and has resulted in industry practice which is sufficiently measurable for application of the prudent operator role. We believe the obligation it establishes is enforceable and fair.

2. The Project Description is Weak and Could Permit an Over the Top Route. First, it should be noted that federal law, Section 103(d) of the Alaska Natural Gas Pipeline Act, prohibits an over-the-top route. Second, Section 4.1 of the fiscal contract identifies the route of the project as the southern route. A change in the project description referenced in Section 4.1 would require an amendment of the fiscal contract which cannot happen without the State's consent. To dispel any lingering concern, however, the State is proposing contract amendments to make more explicit the fact that the fiscal contract is for a southern route project and to add a provision that any change to the contract's route or core economic provisions would be subject to an opportunity for legislative review and approval.

The PFIF provides evidence that the project description contained in the fiscal contract was more comprehensive and detailed than for any comparable project in the world. The fiscal contract requires that the elements of the *Project* as described in Article 4.1 of the May 24 contract must be consistent with the *Qualified Project Plan* which provides details about the expected size and characteristics of the gas pipeline. To dispel uncertainty, the State is proposing a contract amendment that would add language describing those characteristics as opposed to their treatment in the May 24 contract which incorporates them by reference.

3. The State Cannot Practicably Terminate the Contract Even If the Producers Do Nothing. This assertion is made but no analysis to substantiate it is provided. The complete diligence requirement is that "diligence" means advancing the *Project* as diligently as is prudent under the circumstances. Section 5.1. Under this standard, the fiscal contract could easily be terminated if the Producers "do nothing" prior to project sanction because such conduct by definition is not diligent. In fact, as the PFIF explains, the contractual "diligence" standard incorporates essential features of the "prudent operator" standard that is applied to lease commitments. By contrast, the DNR negotiating team did not obtain agreement from TransCanada to terminate any arrangements with TransCanada prior to project sanction even if TransCanada failed to proceed with the project in a diligent manner after the open season.

The comments also ignore the fact that the steps leading up to the filing and processing of the FERC application provide a yardstick against which the Producers' actions in advancing the project or not can be measured. The sponsors are committed to the pre-filing process at the FERC. Both because of federal regulations that lay out that process and because industry practice in complying with that process provides examples of what must be done, it will be relatively easy to determine whether the project is advancing as diligently as is prudent under the circumstances. That process overlaps with the specific open season regulations (including time requirements) for conducting an open season for the Alaska gas pipeline. That is followed by the FERC application process which is subject to statutory deadlines under the Alaska Natural Gas Pipeline Act of 2004. A failure to meet the diligence standard will be measurable by these standards.

4. The Contract Should Contain a Construction Date Deadline or Some Type of Penalties. This ignores the advice of the State's consultants at IPA, which specialize in large projects, that schedule-driven projects invariably encounter major cost overruns and other project obstacles. You also fail to acknowledge the fact that this is an international project, the overall progress of which is dependent on the actions of a foreign government as well as permitting requirements of a host of other governmental agencies. Moreover, design engineering during pre-application and permitting may result in steps which slow the project in order to avoid cost overruns, all of which may be in the interest of the project and the State. Because of widespread public comment on work commitments, the State is proposing to add a letter of credit forfeiture provision that the unpaid balance would accrue to the State's benefit if project sanction does not occur by the fifth year after the sanction date. In

addition, a failure to reach project sanction by that time would be a presumptive failure of diligence. The former DNR negotiating team did not obtain any construction deadlines or penalties from TransCanada.

5. The Contract Provides Too Many Financial Incentives At Values Far Beyond Reasonable and Legislative Consultants Have Shown the Project to be Deeply Profitable. In making these assertions, one needs to be careful not to become more concerned about what the Producers get from a gas pipeline contract than what the State gets. What the State gets is a seamless transition from an oil based revenue stream to a gas based revenue stream without an intervening revenue gap. In ten years oil flows will be half of what they are today. There is an eight to ten year lead time to construct a gas pipeline and obtain revenues. Each year of delay while we argue over what the Producers get, creates risk of a revenue gap and erodes Alaska's bargaining position. The greatest risk to Alaska is not getting a gas pipeline.

The most important incentive that is provided under the fiscal contract is State risk sharing that is achieved by the State taking its gas in kind and owning approximately 20% of the project. This is a position to which Mr. Irwin agreed when he was Commissioner of Natural Resources. As a result, the rate of return and net present value of the project are enhanced. An equally important point is that even with the package of "incentives," the fiscal contract delivers as much value to the State as the status quo. *See* Comm. Corbus letter to Sen. Wagoner, Sept. 27, 2006 at 3-5; FIF at 73.

The legislative consultants demonstrated that the project would be profitable under conditions where a hypothetical gas purchaser would purchase all or most of the gas at the point of production on the North Slope. Under this scenario, the Producers would not have to make any ship or pay commitments (FT commitments) with respect to pipeline transportation. It was widely agreed by all State consultants and the Producers that under these conditions the project would be profitable; however, the hypothetical sale on the Slope is contrary to fact in two respects: (a) the Producers have shown no inclination to let others market their gas, and (b) no such purchaser of all or most of the huge volume of gas expected to be shipped has been identified.

On the other hand, the legislative consultants never provided convincing evidence that the project was profitable to Producers in the situation in which the Producers had to make FT commitments for all of the gas. In fact, under conditions as they exist today (October 1, 2006) with a Henry Hub price of $ 4.26 and an expected cost overrun of more than 50% due to extreme cost escalations in Alberta, the project may be unprofitable notwithstanding the financial incentives provided under the May 24 contract.

6. The Contract Would Cost the State an Amount That Approaches 50% of the Entire Cost of the Project. You do not explain this assertion. We can only assume that you are lumping together indiscriminately the out of pocket cost of the State's investment with hypothetical amounts that are associated with an assumed resolution of contested

royalty tax, and lease issues under current law, and proposed changes in the production tax on both oil and natural gas. There is no rational way of responding to this punch bowl of assorted real and hypothetical issues.

7. Under Low Prices the State Gives Away a Significant Share of the Royalty and Tax Values. The concept of providing incentives with respect to royalty and tax values under low prices was originally proposed by the DNR. The DNR insisted upon and specifically endorsed in the October 29, 2004, proposal that included the Price Differential Payment (PDP) based on a so-called S-curve. Under this concept, the State would agree to make significant payments to the Producers when Chicago well head prices would be less than $3.50 per MMBtu.

8. At Any Gas Price the Contract Saddles the State Proportionately With More Costs and Risk Than the Producers. This statement is devoid of any economic or technical backup from you. There is no evidence that the costs to be contributed by the parties to participate in the midstream project will be anything other than proportional. A full analysis of what the State agreed to in the fiscal contract is contained in the Letter of Commissioner William Corbus to Senator Thomas H. Wagoner of September 27, 2006, at 3-5. The conclusion of the letter after that analysis is directly responsive to the ultimate thrust of your comment:

> "If one believes that despite the evidence of the last quarter century a gas pipeline is wildly economic, one will also believe that the state was not as assertive at extracting rents from the project as it ought to have been. If however one believes, as I and the team of experts, both within and from without the state government do, that the project is one that carries large risks and may not appear as likely to be built when compared with industry investments around the world, then our negotiations were more than just dividing up the project's economic rents. We were attempting to create an environment in which such a project would be more likely to be undertaken. We succeeded. In the end concern about what the Producers get instead of getting a pipeline for the state will lead to the greatest risk to Alaska—not getting a gas line at all."

Letter at p. 5.

The risk under the proposed fiscal contract is far less than the extreme risks and unfavorable disproportionality for the State provided to TransCanada under the terms proposed by your former DNR team. The State proposed contributing 50% of the high risk pre-open season development costs for the project but was not granted the ability to participate proportionately in the Alaska portion or Canadian portion of the line. Also the State would be required to commit to a huge FT commitment on the Canadian portion of the line without corresponding pipeline ownership.

Furthermore, the State would have to consider making an extremely high risk price offer to the Producers for the purchase of a large volume of gas. Under this proposal the State would be bound by its offered price under low prices and give the Producers the flexibility to opt in under favorable price developments, thereby relinquishing the price upside to the Producers.[2]

9. The State Should Not Pay for Any Production and Development Costs. As indicated under item 7, the former DNR team proposed a PDP on October 29, 2004, whereby the State would pay for a share of production and development costs under low prices. Under current law, Alaska would pay some costs for gas production and development. This is the result of the 1980 Prudhoe Bay field cost settlement agreement which you disfavor. The oft-expressed critical views of the former DNR team regarding the 1980 settlement illustrate precisely why the Producers have argued so aggressively for fiscal stability. In any event, even inclusive of the payment of some production and development costs, the fiscal contract is equal to the economic status quo. PFIF at Table 6 @ 73, 75.

10. & 25. The Contract Forces the State to Market its Own Gas, Competing Against the World's Open Market; Under the Current Leases it Gets the Advantage of the Producers' Marketers At No Cost. Complaints About the Mechanics of Gas Marketing With the Conclusion That the State Should Not Take Its Gas in-Kind. The PFIF, in Sections 6.3.1, 6.3.2, and 8.2.1.4, provides extended discussions of market risks and the options available to the State to market our gas. The State will indeed compete directly with the Producers. The Producers are not likely to be advantaged upstream due to the unique position of the State marketer, which, alone, will enjoy the perspective from upstream information received from each of the North Slope Producers and may also have tax advantages over the Producers' taxable marketing efforts. *See also* Backbone II Response at 23-24. It is false to say that the State benefits from the Producers' superior marketing at no cost. The Producers' costs of marketing are a deduction from the "net proceeds" that the State receives. In addition, the Producers can be expected to market their gas in the markets that best suit the business objectives of their overall portfolio of gas supplies including lower 48 supplies, not where they necessarily will achieve the best results for the State, such as selling gas for in-state needs.

You pessimistically assume that the State cannot manage the marketing of its natural resources. If the same assumption had been applied to the Permanent Fund, its only investments would be bank savings account or government bonds. In fact, the Permanent Fund has used professional advisers to invest in a diversified portfolio of assets with very successful long-term results. The State has the same opportunity to successfully manage its gas assets.

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[2] The TransCanada team never analyzed how that offer would or could be financed consistent with legal constraints that apply to contractual commitments by the State.

The draft study you reference regarding the cost of the capacity terms was based on a review of an earlier version of the capacity clause. The Lukens report was updated and revised to reflect the final capacity management article. It shows greatly reduced risk. You emphasize the costs and risk of taking gas in-kind and ignore the costs and risk of taking gas in-value — namely the need to repeat decades of costly litigation to ensure "full value" is received for the State's gas. The PFIF addresses the cost and risk of the State taking its gas in-kind and concludes that the State will likely do as well as if it took gas in-value and has the opportunity to do better.

As far as the allegation that the State should not take its royalty and tax in-kind, the DNR recommended to the Governor that the State should take its royalty and tax in-kind in its endorsement of the October 29, 2004, proposal. The Governor relied on this recommendation to approve the initial proposal to the Producers and in conducting the negotiations. If the State does not take its gas in-kind, there is less opportunity for in-state use of Alaska's gas.

Finally, you fail to recognize the greatest risk of all to the State—not getting a gas pipeline. If a gas pipeline is not in operation in ten years, where will the revenue come to replace oil production, which by 2016 will be 50% less than today's production levels?

11. The Comment Is Made Under the Contract That the State Largely Surrenders the Power of the Executive, Legislative and Judicial Branches, As Well As The Right to Vote Initiatives, For Up to 45 Years. The Legislature enacted the SGDA and authorized a term as long as 35 years from the commencement of commercial operations, which could work out to a term of 45 years. *See* letter to Sen. Gene Therriault of 8/31/06 at 12-13. The commencement of commercial operations is likely to occur eight to ten years after the effective date of the fiscal contract. The May 24 contract was negotiated within the term authorized by the Legislature; your comments may be read as a disagreement with the Legislature about the terms of the SGDA. If there is a question about the legality of such a term or the conditions surrounding it, it will be settled by the Alaska Supreme Court. The Attorney General has opined that the term of the May 24 contract and the related fiscal stability conditions for taxes are constitutional.

Nonetheless, because of widespread public concern about the term of the fiscal contract, including comment from the Legislature itself, the State is prepared to propose a shorter term of fiscal stability—of twenty five years from the commencement of commercial operations with a carve out of a different term and concept for fiscal stability for the provisions relating to the new Petroleum Production Tax (PPT), State Corporate Income Tax (SCIT), and pipeline *ad valorem* taxes. For the PPT clause, the term would be divided into three periods with no fiscal stability provided up to the time of project sanction; with stability for fourteen years from project sanction but with the applicable taxes being frozen as of the later of the last day of the 2011 legislative session or the FERC application date, and with a fiscal stability clause for the remaining balance of the time left from 25 years from the effective date. The tax provisions for SCIT and *ad valorem* taxes also would be trimmed back.

Your comments reference a surrender of voter initiatives. We assume you have in mind the reserves tax that is on the ballot this November. The incumbent Governor and all three candidates for Governor have rejected the notion that the reserves tax is an incentive to moving the project forward. Governor Murkowski has said for over a year that a reserves tax would be counterproductive to the advancement of the gas pipeline. The fiscal contract does not restrict the voters' right to pass initiatives, but consistent with the concept of fiscal stability, it provides the Producers with protection from any initiative directed at the project.

Your final comment references surrendering the power of the Alaska judicial system to arbitration. The DNR before, during, and after your leadership included arbitration clauses for disputes involving the royalty reopeners in all of its royalty settlement agreements and the State has had very successful results in an arbitration under those provisions. The first full fiscal contract that the State offered to the Producers included arbitration and senior Administration officials involved in the negotiations, including former Commissioner Irwin and former Deputy Commissioner Rutherford, approved that contract.

In praising the judicial system, your comments ignore the fact that disputes over royalty valuation have taken decades to resolve at great cost and without a finally litigated result in any major case. Your comment appears to advocate litigation at any cost and for any time as preferential to the State.

Finally, you make a general reference to weak arbitration standards. It is difficult to respond to such a general comment. The arbitration clause was carefully drafted to address the different kind of disputes that might arise in the future, which will be different from, and narrower than, the ones of the past. For example, because the State is taking royalty gas in-kind and tax payments in gas and doing its own marketing, there simply will not be the kind of massive royalty and tax valuation disputes that have occupied so much time and resources for so long. Also, many of the payments due under the fiscal contract result from simple mathematical calculations.

12. <u>The Contract Changes the State's Relationship With the Oil and Gas Industry By Making the State a Minority Business Partner Rather Than a Resource Owner and Regulator</u>. This is a serious misrepresentation. The State did not in the fiscal contract give up its role as resource owner and regulator. The fiscal contract seeks to promote the development of the Alaska resources by creating a new role for the State as business partner in addition to its role as resource owner and regulator.

The concept of having active sovereign participation as an equity co-investor in projects with the petroleum industry is a widely used concept around the world and is a proven method of enhancing total benefits. Alberta, Nova Scotia, the UK, Norway, the Netherlands and many other nations use this concept. In addition, important long distance gas exporters often have included an important direct role for the sovereign as business partner and gas marketer, such as Russia, Algeria, Qatar, Oman, Malaysia, Libya and others.

13. The Contract Does Not Assure Gas for Alaskans at Reasonable Rates and Times. How gas will be provided to in-state users is a policy choice for the State as it markets the large amount of gas it will have under the fiscal contract. It is not a proper subject for a fiscal contract that is intended to provide a fiscal foundation for the gas that will advance the project. How the State sells its gas is not a matter for negotiation with the Producers and is not a proper subject for the fiscal contract.

The State will own approximately 20 % of the gas, approximately 1 bcf per day, which is far more than any reasonable projection of likely in-state needs. Thus, the State will be in a position to provide gas for in-state needs and the Administration is announcing a policy to provide for those needs. A future administration will decide the price for sales of the State's own gas to in-state users consistent with the requirements of the Alaska Constitution about obtaining maximum value for the disposal of the State's resources. Given the large amount of gas that the State will control, the favorable FERC rulings on in-state rates, and the fiscal contract provisions for off-take points and interconnection, it would be superfluous for the State to negotiate a requirement for the Producers to supply gas at a predetermined price for in-state use. The Producers may choose to sell gas for in-state users if any of them wishes.

The proper starting point for addressing rate concerns is the FERC's final open season regulations. They require the pipeline to offer both in-state and out of state rates with the in-state rates being distance sensitive and reflective only of the costs of providing in-state service and not inclusive of costs beyond Alaska. These requirements assure that in-state rates will be constructed on the most favorable basis for Alaska.

The fiscal contract reaffirms this requirement by obligating the project to offer a mileage sensitive rate in the open season and to study in-state needs before the open season. The fiscal contract provides for the project to construct at its expense four offtake points for service inside Alaska and also provides that the pipeline must cooperate in interconnecting with in-state pipelines that want to connect to the gas pipeline.

14. The Contract Does Nothing to Assure Lowest Reasonable Transportation Costs. Gas pipeline rates are subject to extensive regulation by the FERC. Gas pipeline regulation is the everyday business of the FERC and the FERC has been vigilant in setting rates that protect shippers.[1] Moreover, the project entity governance agreements will set a target capital structure of 80%/20% debt/equity ratio, seek maximization of the use of federal loan guarantees to reduce the cost of debt, and commit to seek project-level financing if available on acceptable terms. These all will combine to produce reasonable rates. In the fiscal contract, the State has

[1] The FERC has not adjudicated TAPS rates to date. It only approved a settlement between the TAPS carriers and the State that is responsible for the level of TAPS rates. The complete story of TAPS rates is a story that would take a long time to address and is not relevant to gas pipeline issues.

reserved the right to protest TAPS rates at the FERC if it feels the resulting rates are in any way excessive.

An independent pipeline that has no Producer affiliates has a strong incentive to maximize rates because its business objective is to charge the highest rates it can achieve in order to maximize its revenues. A pipeline with affiliated shippers does not have the same incentive because, from an economic perspective, higher rates reduce the profits from the sale of gas by the affiliated shippers. There is only one limited case where an affiliated pipeline might want to keep its rates higher and that is where those rates are a deduction from in value royalty and tax payments. In that one case, high rates serve to lower royalties and tax payments. Since the State is taking royalty gas in-kind and receiving tax payments in gas, that incentive does not exist in this case.

15. The Contract Fails to Create a Level Playing Field for the Producers' Competitors by [Not] Demanding Regular Expansion of the Gas Pipeline to Accommodate New Explorer Company Gas Nor Reasonable Expansion Tariff Structures. The argument suggests that independent explorers will successfully find and develop new fields on a predictable and certain basis. Exploration is simply not that predictable and certain. If the pipeline had to spend large sums to expand at pre-ordained times and in pre-ordained dimensions regardless of the needs for such expansions, FERC policy would require the pipeline's owners, including the State, to absorb the significant costs of any unnecessary expansions. This would serve to increase the economic risk of the project and the cost to the State.[4]

If the pipeline does not accommodate explorers, explorers have an unprecedented right under this project to go to the FERC and ask it to use its unprecedented powers to order expansion. Because of advocacy by the State and other pro-exploration interests, the FERC adopted open season rules that favor expansion specifically by adopting a presumption of rolled-in pricing in Alaska. In doing so, the FERC reversed its lower-48 policy on the pricing of expansion capacity precisely to address explorers' concerns. Going beyond this to require a one-size-fits-all policy on expansion could produce a subsidy for explorers and could be costly to the State's financial interests.

16. The Contract Gives Exxon (As the Unit Operator for the Point Thomson Unit, PTU) a 45-year Extension on Its Lease Requirements to Develop the State's Oil and Gas Resources at Point Thomson. Exxon Has Already Held These Leases for More Than 30 Years Without Developing Them. It is Profitable to Develop the Oil on These Leases Now, Even Without a Gas Pipeline Project. The first statement in this series is false. No objective reading of the fiscal contract can lead to the conclusion stated. The second statement is inadequate and misrepresents PTU history. The last statement is unsupported, and requires access to information not available to you, and

[4] The alternative, a sole risk expansion clause, would place the cost and risk of expansions solely on the State. *See also* the discussion of expansion in the letter of James Clark, August 31, 2006, to Sen. Gene Therriault at 9-11.

it begs the issue that development of the PTU gas resource appears to be the major prize to be obtained from these leases.

During contract negotiations, it became clear the Producers felt very uncertain about the status of PTU, particularly given its critical importance to the gas pipeline economics. The amended DNR decision of October 27, 2005 found the Point Thomson Unit (PTU) Agreement to be in default. That decision did not call for the return of the PTU leases to the State, but it did call for "a plan to bring the PTU into commercial production within a reasonable time frame" and provided dates for initiation of development operations, commencement of drilling, and commencement of production. Because these dates are inconsistent with the work commitments contained in the fiscal contract, extensions of the time period within which the operator can appeal that default decision have been given, pending conclusion of deliberations on the fiscal contract by this Legislature. With the conclusion of legislative deliberations on the fiscal contract, the appeal deadline has now been reinstated by the Commissioner of Natural Resources.

The decision to include PTU in the fiscal contract was a reasonable and necessary step, given the critical importance of PTU reserves and deliverability to the fiscal contract. That step was taken, while imposing specific requirements upon the Producers:

- Each Producer must commit PTU gas reserves to the gas pipeline project;
- The Producers must apply to the Alaska Oil and Gas Conservation Commission (AOGCC) within six months for issuance of pool rules
- In addition, the fiscal contract requirement that the gas pipeline project be pursued "with diligence" exists, and applies to PTU development, as well as the rest of the gas pipeline project – if the fiscal contract is terminated for any reason; according to the contract terms, the Producers' rights to Point Thomson expansion leases terminate unless they initiate development within one year of the contract termination. In addition, the DNR can also pursue other steps, including termination of the unit, and initiating procedures to revoke the leases.

Finally, nine months after startup of the gas pipeline, commitments to DNR Plans of Development resume, which will allow the DNR to continue to manage development of PTU oil and gas reserves.

Historically, continuance of the PTU unit and leases has, until the latter half of 2005, been with the concurrence of Commissioners of Natural Resources of several administrations of varied political perspectives. The PTU leaseholders have invested significant amounts of money over several decades in exploring this acreage and in addressing major technical issues. In recognition of those facts, each of these administrations has been a party to extending these leasehold interests. The amended DNR decision of October 27, 2005, has placed these

companies on notice that development must now proceed. The fiscal contract provisions concerning PTU provided a specific context for that development. Since those deliberations have now ended, the PTU leaseholders are back to dealing directly with the DNR to develop an acceptable Plan of Development (POD) which will lead to field development.

On September 8, 2006, the Commissioner of Natural Resources issued a final extension of time to submit a cure to the October 27, 2005, decision placing the PTU in default. That cure, with all supporting documentation, must be submitted to the DNR no later than October 20, 2006. In addition, any party wishing to submit an appeal on the subject must submit all appeal documentation to the DNR by November 3, 2006. The Commissioner of Natural Resources will hold an appeal hearing on November 13, 2006. Any decision concerning the cure and any appeals will be made by the Commissioner of Natural Resources subsequent to the November 13 hearing.

17. Improper Indemnification. The comments do not identify the risks that are improperly indemnified. The fiscal contract in no way indemnifies Producers against "most risks." The State does not indemnify, for example, for either cost overrun risk or the risk of gas price fluctuation. The indemnities that are provided are quite specific and tailored to the purposes of the fiscal contract. In Article 10, for example, the State agreed to indemnify, except in cases of fraud, the Producers' capacity holding entity when it acts to acquire capacity for the State. This is a fair exchange in return for the capacity holder entity taking on the unprecedented obligation to keep the State on an equal footing with the Producer in the acquisition and retention of capacity shipping rights. *See* Backbone Response June 2, 2006, ¶ 18. The State is proposing contract amendments to insure that the fiscal contract will conform to the opinions of the Attorney General on State indemnities.

18. Shield for the Reserves Tax. No gubernatorial candidate nor any responsible analyst supports the reserves tax as providing an incentive to build the gas pipeline. Your comments provide no analysis or explanation to suggest that it will. The fiscal contract shields the project against any reserves tax. A reserves tax could cost the Producers $ 1 billion per year and remove an incentive to build the gas pipeline, because this tax would make the pipeline uneconomic. The additional $1 billion per year can only be partially recovered by the Producers if the line commences operations and therefore puts an additional burden on a project that already requires fiscal incentives to be attractive under current economic conditions. The reserves tax would be payable during planning, regulatory process and construction of the gas pipeline and therefore provides no incentive to build the pipeline, because the tax must be paid regardless of whether the pipeline is being constructed or not.

If Alaskans adopt such a reserves tax, the Producers will very likely fight this tax in court which in turn has the potential to set the possible date for an agreement between the State and the Producers back by at least two years until the reserves tax can be repealed. *See also* response to Mayor Cottle June 21, 2006, ¶ 6C (p 9). The State cannot afford a delay in the project without

incurring serious revenue shortfalls ten years from now as oil revenues decline and the gas revenues are not online.

While the reserves tax issues are fought out, the clock ticks and time is not in the State's favor. Alaska must make the transition from an economy based on oil revenues to one based on natural gas sales. Without a gas pipeline, it is projected that crude oil production will decline and end in 2030. A decade before that time oil production could be at half current levels. Given that the gas pipeline will take eight to ten years to come to fruition, time is precious and short. See PFIF at 4 to 10. A reserve tax would be a major step backwards towards securing a gas pipeline that is essential to Alaska's future.

19. Waiver of State Immunity from Lawsuits. The May 24 contract does not waive the State's immunity from lawsuits of all kind. To the contrary, the Producers must resolve their disputes through the contractual arbitration process and cannot resort to courts in Alaska or elsewhere to resolve disputes. In certain cases, the May 24 contract provides that an arbitration award can be enforced outside Alaska but only if an Alaska court has not entered a judgment to enforce the award after one year. The State is proposing a contract amendment that would eliminate any possibility of enforcement of arbitration awards against the State in an Alaska or other court. The remedy for such an award would be limited to an appropriation by the Legislature or collection of the amount through the waterfall of payments related to the fiscal contract.

20. Alaska Loses the Protection of Resort to Its Courts. As noted above, the DNR had been a proponent of, and user of, arbitration. International projects use arbitration to settle disputes. Your comment ignores the cost and delay attendant in using the court system and assumes that the Alaskan courts exist to apply the law in the State's favor when in fact they are charged by law with being impartial to all parties.

Without specificity, the comments assert that the arbitration rules are heavily slanted to favor the Producers. To the contrary, they are a reasonable and balanced set of rules tailored to the nature of disputes that might arise under the fiscal contract. *See* Response to Hon. Bert Cottle, June 21, 2006, ¶ 4, p 7-8. As we have discussed earlier, many of the old tax and royalty disputes will not arise in the future because the State is taking its gas in-kind. The State is proposing a set of improvements to the arbitration clause in light of public comment, however.

21. & 22. The Long Term of the Contract and the New PPT. The Contract Incorporates the New Production Tax with a Fiscal Certainty of 45 Years. Your comment is incorrect. The May 24 contract does not provide for fiscal certainty on the oil production tax for 45 years. The May 24 contract fiscal stability for oil was 30 years ending on December 31, 2036. The Legislature has enacted a new PPT. The State is proposing a contract change that will further shorten the term for fiscal stability on oil overall and delay the start of fiscal stability overall on oil until project sanction. *See* p.14 *supra*.

CORRECTION

THE FOLLOWING DOCUMENT(S)
HAVE BEEN REFILMED TO
ASSURE LEGIBILITY OR PAGINATION

incurring serious revenue shortfalls ten years from now as oil revenues decline and the gas revenues are not online.

While the reserves tax issues are fought out, the clock ticks and time is not in the State's favor. Alaska must make the transition from an economy based on oil revenues to one based on natural gas sales. Without a gas pipeline, it is projected that crude oil production will decline and end in 2030. A decade before that time oil production could be at half current levels. Given that the gas pipeline will take eight to ten years to come to fruition, time is precious and short. See PFIF at 4 to 10. A reserve tax would be a major step backwards towards securing a gas pipeline that is essential to Alaska's future.

19. Waiver of State Immunity from Lawsuits. The May 24 contract does not waive the State's immunity from lawsuits of all kind. To the contrary, the Producers must resolve their disputes through the contractual arbitration process and cannot resort to courts in Alaska or elsewhere to resolve disputes. In certain cases, the May 24 contract provides that an arbitration award can be enforced outside Alaska but only if an Alaska court has not entered a judgment to enforce the award after one year. The State is proposing a contract amendment that would eliminate any possibility of enforcement of arbitration awards against the State in an Alaska or other court. The remedy for such an award would be limited to an appropriation by the Legislature or collection of the amount through the waterfall of payments related to the fiscal contract.

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The constitutionality of the term of the May 24 contract has been addressed at length by the Attorney General in a memorandum dated May 10, 2006.

23. The Proposed Production Tax is Based on "Profit" Which is Complex and Will Result in Conflict With the Producers. Petroleum taxes on net revenues have made Norway and Alberta among the two richest jurisdictions on earth because these taxes tend to yield considerably more government revenues while at the same time stimulating investment in exploration and new developments. For 2006, the production tax will increase State revenues by an estimated one or two billion dollars. This fact has not been disputed. As long as oil prices remain over $30 per barrel, revenues will exceed those received under the previous Economic Limit Factor (ELF) based formula. It was widely recognized by all legislators that the current system was broken and needed revision. The argument about gross v. net production taxes was exhaustively debated in the Legislature. A gross tax does not provide an incentive for investment. The Producers must increase their investment in oil production from $1.0 billion per year to $1.8 billion per year just to cut the annual rate of oil flow decline from 6% to 3%. After a regular and two special sessions, the Legislature voted to enact a tax based on net revenues because they recognized this point.

It should be noted that in order to achieve acceptance on the part of the Governor for the approval of the TransCanada term sheet and to encourage the Governor to do a deal with TransCanada rather than with the Producers, the former DNR team proposed at several times in early and mid-2005 to grant the Producers "fiscal certainty" on the pre-2005 "status quo" for a 35 year period as part of the overall deal. The fiscal results for the State would have been devastating had the Governor accepted this former DNR team recommendation. The former DNR team recommendation would have enshrined a "broken" system for 35 years, resulting within a few years in near zero production taxes on oil production.

24. Disproportionate Risk at Any Price and the Gas As Not Stranded. This statement is a repeat of items 5 and 8. The item 5 and 8 issues have already been answered above. So has the issue of the economics of the gas. Under current price and cost conditions the project is uneconomic. We also note that when Mr. Irwin served as Commissioner of Natural Resources, he and Commissioner Corbus co-signed a letter to the Producers dated January 23, 2004, approving its application as one that qualified under the requirements of Section 130 of the Stranded Gas Development Act including the requirement the their application "reflects a proposal for diligent development of the project on the part of the applicant." If Mr. Irwin then believed that North Slope gas was not stranded, he would not have co-signed the January 23, 2004 letter approving the application. For sake of historical reference, the Henry Hub price for January 2004, was $6.03/Mmbtu. Last Friday's price was $4.26/Mmbtu.

26. Comments Concerning Regulatory commission of Alaska (RCA) Jurisdiction and the Potential Absence of FERC Jurisdiction. The hypothetical scenario that the FERC