FISCAL NOTE

STATE OF ALASKA
2006 LEGISLATIVE SESSION

Fiscal Note Number: 1
Bill Version: HB 2004
(H) Publish Date: 5/31/06

Revision Date/Time (Note if correction):
Dept. Affected: Revenue
Title: Stranded Gas Development Act Amendments
RDU: Administration and Support
Component: Commissioner's Office
Sponsor: Rules Committee
Requester: Governor
Component No. 123

Expenditures/Revenues (Thousands of Dollars)

Note: Amounts do not include inflation unless otherwise noted below.

OPERATING EXPENDITURES	FY 2007	FY 2008	FY 2009	FY 2010	FY 2011	FY 2012
Personal Services						
Travel						
Contractual						
Supplies						
Equipment						
Land & Structures						
Grants & Claims						
Miscellaneous						
TOTAL OPERATING	0.0	0.0	0.0	0.0	0.0	0.0
CAPITAL EXPENDITURES						
CHANGE IN REVENUES ( )						

FUND SOURCE (Thousands of Dollars)

1002 Federal Receipts						
1003 GF Match						
1004 GF						
1005 GF/Program Receipts						
Bond Proceeds						
Bond Bank Investment Earnings						
TOTAL	0.0	0.0	0.0	0.0	0.0	0.0

Estimate of any current year (FY2006) cost: 0.0

Mark this box (X) if funding for this bill is included in the Governor's FY 2007 budget proposal: [ ]

POSITIONS

Full-time						
Part-time						
Temporary						

ANALYSIS: *(Attach a separate page if necessary)*

This bill amends the Alaska Stranded Gas Development Act (AS 43.82) (SGDA) to clarify and/or provide additional authority for the development of stranded gas fiscal contract terms. Funding for negotiations under the SGDA has been previously provided and no additional funding is required as a result of this legislation.

Prepared by: Jerry Burnett
Phone 465-2312
Division: Administrative Services
Date/Time 5/9/06 12:00 AM
Approved: Steve Porter
Date 5/9/2006
Agency: Department of Revenue

(Revised 9/7/2005 OMB)

FISCAL NOTE

STATE OF ALASKA
2006 LEGISLATIVE SESSION

Fiscal Note Number: 2
Bill Version: HB 2004
(H) Publish Date: 5/31/06

Revision Date/Time (Note if correction):
Dept. Affected: Natural Resources
Title: Stranded Gas Development Act Amendments
RDU: Resource Development
Component: Oil and Gas Development
Sponsor: Rules by Request of the Governor
Requester: Governor
Component No. 439

Expenditures/Revenues (Thousands of Dollars)

Note: Amounts do not include inflation unless otherwise noted below.

OPERATING EXPENDITURES	FY 2007	FY 2008	FY 2009	FY 2010	FY 2011	FY 2012
Personal Services						
Travel						
Contractual						
Supplies						
Equipment						
Land & Structures						
Grants & Claims						
Miscellaneous						
TOTAL OPERATING	0.0	0.0	0.0	0.0	0.0	0.0

CAPITAL EXPENDITURES						
CHANGE IN REVENUES ( )				**Indeterminate		

FUND SOURCE (Thousands of Dollars)

1002 Federal Receipts						
1003 GF Match						
1004 GF						
1005 GF/Program Receipts						
1037 GF/Mental Health						
Other (Specify Type—Do not abbreviate)						
TOTAL	0.0	0.0	0.0	0.0	0.0	0.0

Estimate of any current year (FY2006) cost: 0.0
Check this box (X) if funding for this bill is included in the Governor's FY 2007 budget proposal: ☐

POSITIONS

Full-time						
Part-time						
Temporary						

ANALYSIS: *(Attach a separate page if necessary)*

This bill would modify authorization granted to the Commissioner of Revenue to negotiate a contract under AS 43.82. By itself, such modified authorization has zero fiscal impact. Fiscal effects can occur only if a contract is negotiated under the new authorities that changes the status quo fiscal terms or imparts additional costs on the department. This analysis therefore presumes that the draft contract released on May 10, 2006, and discussed in the Commissioner of Revenue's Fiscal Interest Finding is executed. It further assumes that a gasline is constructed as a result of that contract.

** INDETERMINATE. The Fiscal Interest Finding finds that North Slope gas resources would not be developed but for the terms of the proposed contract. It logically follows that long-term (45 years) net fiscal impacts of the bill's authorization, combined with the proposed contract, are very large and positive – on the order of $12 billion in net present value, according to the Fiscal Interest Finding. The rest of this analysis describes DNR's assessment of costs and benefits associated with various contract provisions that would be authorized by this bill as they affect royalties – costs and benefits that have been largely included already in the Fiscal Interest Finding's assessment of overall net State benefits. (Continued)

Prepared by: William Van Dyke, Acting Director — Phone 269-8800
Division: Oil and Gas — Date/Time 5/19/2006
Approved by: Michael Menge, Commissioner — Date 5/19/2006
Agency: Natural Resources

FISCAL NOTE #2

STATE OF ALASKA **BILL NO.** HB 2004
2006 LEGISLATIVE SESSION

ANALYSIS CONTINUATION

Sections 2 and 5 of the bill permit a contract negotiated under AS 43.82 to include contract terms that modify provisions of applicable oil and gas leases, unit agreements and other agreements under AS 38 Under the contract (Article 12), the State will agree to take its royalty gas in-kind (RIK) for 35 years. Taking its royalty gas in-kind, with delivery at the first point of accurate metering, entails revenue losses over the life of the contract for the State compared with taking royalty gas in-value (RIV). These revenue losses presume that the gas resources could be developed within a similar timeframe under the existing 2005 fiscal system and include:

- The lost value that the State might receive under its "higher-of" RIV lease valuation provisions. Such value has been estimated at approximately 2 percent of the destination value of the gas. Assuming a \$5.50 real gas price, the loss of this 2 percent has an undiscounted real cost of roughly \$540 million, or \$270 million discounted at 3 percent, over 35 years.
- Costs of putting royalty gas either from non-DL-1 leases or from DL-1 leases outside of Prudhoe Bay Unit into marketable or pipeline quality condition at the Gas Treatment Plant. The State's position has consistently been that it is not responsible for such costs in an RIV framework. Over 35 years the real undiscounted cost to the State of paying these costs will total approximately \$460 million, or \$220 million discounted at 3 percent.
- Gas marketing. The State will market its RIK gas – a service provided free under RIV lease terms. The State conservatively estimates that this will cost 5 cents per Mcf. This equates to \$310 million (undiscounted, real dollars), or \$160 million discounted at 3 percent. DNR would also bear costs in assembling a marketing organization.
- The lost option value associated with the ability to switch between receiving gas RIV and RIK. Based in part on a negotiated (but never executed) RIK gas sale contract that exploited this option value, the State estimates that the ability to switch between RIK and RIV is worth roughly 2 cents/Mcf. This comes to an undiscounted real figure of \$110 million, or \$60 million discounted at 3 percent.
- Costs of impurity disposal. These costs will be the subject of a future negotiation between the owners of a gas treatment plant and a Unit's working interest owners; they will include all full-cycle, direct, indirect, incremental and consequential costs (see Article 8.5) for disposal of water, carbon dioxide and hydrogen sulfide. The State estimates that each 1 cent/Mcf charge for impurity disposal will reduce undiscounted real royalty value by \$11.6 million, or \$4 million discounted at 3 percent. Full-cycle disposal methods and costs have not been estimated to date nor has any positive value been assigned to the impurity stream.
- Costs associated with potentially increased pipeline transportation charges on existing North Slope pipelines (e.g. the existing Northstar pipelines, the Oliktok pipeline, the Badami pipeline). Taking gas RIK will require the State to pay Federal Energy Regulatory Commission approved tariffs. FERC tariffs will likely be based on an existing pipeline's replacement value, rather than its book value (see Article 8.6). However, original DL-1 leases issued do not specify a FERC transportation deduction for determining RIV value. If the State were to argue for and prevail on some notion of "actual and reasonable" pipeline costs, then the RIV transportation deduction might reflect the book rather than the replacement value of existing pipelines. The State has not quantified these costs.
- Costs associated with long-term storage. For RIV valuation purposes long-term storage is generally considered to be a marketing cost, and therefore is not a cost the State would reimburse. Under RIK, the State will pay gas storage fees to the extent RIK gas is stored. The State has not quantified the extent of such costs.
- Sections 2 and 5 also authorize the State to agree to pay an Upstream Cost Allowance (UCA) (Article 20) on all royalty gas. At 22.4 cents/Mcf, escalating with inflation, the State will receive approximately \$590 million (undiscounted, real dollars) or \$50 million (discounted at 3 percent) less than under an RIV regime. The 1980 Royalty Settlement obligates the State to pay a UCA for gas produced from the Prudhoe Bay Unit; gas produced from other units is not obligated to pay a UCA.

Section 2 of the bill authorizes the State to acquire an interest in the project. Article 7.2(a) of the draft contract requires the State to own a 20 percent interest in the Gas Treatment Plant, the Alaska to Canadian border pipeline, and the Canadian border to Alberta pipeline. If the cost for these elements holds at 2001 estimates, indexed to inflation, the State will spend roughly \$2.7 billion. The Fiscal Interest Finding finds that, for both royalty in-kind and tax in-kind gas, net earnings from the pipeline are roughly \$707 million (undiscounted, real) or \$577 million (discounted at 3 percent) (Table 12). Roughly two thirds of this benefit can be ascribed to increased royalty value (\$471 million undiscounted and \$385 million discounted at 3 percent).

Article 7.2(b) requires the State to take an ownership interest, commensurate with its share of expected throughput, in gas transmission lines from all existing units. These costs are unknown as they remain to be negotiated. Depending upon the ultimate purchase price demanded of the State, the net benefits to royalty value may be either positive or negative.

Article 7.2(c) requires the State to take an ownership interest, commensurate with its share of expected throughput, in a gas transmission line from the National Petroleum Reserve Alaska, to a Gas Treatment Plant or the mainline if that transmission line is sanctioned before commencement of commercial operations. Because the State will likely have minimal or no royalty gas in-kind traveling on such a pipeline, the value for royalty will be largely unaffected.

Finally, Sections 2 and 5 of the bill permit modification of unit and other agreements. Article 23.2 of the contract makes use of this authorization. The fiscal effects of this Article, which prohibits the DNR Commissioner from altering or modifying the rate of development at PTU, or from enforcing the Point Thomson Expansion Agreement, are indeterminate.

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29 May 2006

Alaska State Legislature
Legislative Budget and Audit Committee
State Capitol
Juneau, Alaska 99801-1183
Attention: Senator Gene Therriault and Representative Ralph Samuels

Gentlemen:

We have been engaged as a consultant advisor to the Legislative Budget and Audit Committee ("LB&A") of the Alaska State Legislature ("Legislature") in connection the legislative review of a proposed fiscal contract ("Fiscal Contract") among the State of Alaska ("State") and certain producers of petroleum from leases on the Alaska North Slope ("Producers") presented by the administration of Governor Murkowski ("Administration") under the Stranded Gas Development Act ("SGDA"). The LB&A has asked us to review the Fiscal Contract, identify some of our major concerns, and prepare a summary of those concerns. In the summary the LB&A has asked us to include: (a) a brief narrative description of each concern; (b) suggested solutions to each concern, except where a concern is a clearly matter of policy for the Alaska State Legislature ("Legislature"); and (c) where a concern is clearly a matter of policy, provide pros and cons relative to such concern.

MATERIAL EXAMINED:

In connection with this summary, we have reviewed the SGDA, the proposed amendments to the SGDA, the Administration's Preliminary Fiscal Interest Finding ("FIF"), the draft of the Fiscal Contract dated 10 May 2006, and the materials furnished by the Administration in connection with its presentations of the FIF and the Fiscal Contract in Juneau, Alaska during the period 10-23 May 2006 (collectively as the "FC Documents").

As to certain questions of fact that are material to our analysis, we have, with your permission and without independent investigation, assumed that: (a) the FC Documents are a complete and accurate listing of all material documentation which as of the last day of the Administration's presentations (23 May 2006) was publicly available relating to the proposed transactions under the SGDA; and (b) the copies of the FC Documents submitted to us for review conform in all material respects to the originals of the FC Documents.

As to certain questions of law that are material to our analysis, we have relied, with your permission and without independent investigation, on the public opinions of the Attorney General of the State of Alaska concerning the constitutionality and enforceability of the SGDA and Fiscal Contract.

SUMMARY OF OBSERVATIONS:

On the basis of the material examined and the assumptions set out above and subject to the qualifications and limitations set out below, we have at this time made the following observations:

CONTEXT:

Alaska's oil and gas arrangements use a lease structure, generate government take through a royalty tax regime, and are managed and controlled through comprehensive regulation. By enacting the SGDA Alaska has decided that in order to more effectively compete with other oil and gas producing jurisdictions for new investment the State will consider altering the status quo for its oil and gas arrangements.

In its presentations the Administration has compared Alaska's oil and gas arrangements to the arrangements of several other jurisdictions particularly with respect to: work commitments, government take, contract duration, and fiscal stabilization. Comparisons are powerful tools to aid in understanding, but to be valid the comparisons must be understood in context.

The most direct comparison for Alaska would be to the oil and gas arrangements of other jurisdictions, which use a lease structure, a royalty tax regime, and comprehensive regulation, such as Alberta, Canada, Deepwater US, Norway, and the UK. However, Canada, Norway, the UK, the US and other jurisdictions using a lease structure, a royalty tax regime, and comprehensive regulation do not provide fiscal stabilization.

The Administration cited Angola, Azerbaijan, Nigeria, Kazakhstan, Qatar, and Russia, as examples of jurisdictions which do provide fiscal stabilization. However, the comparison is difficult because those jurisdictions generally use a production sharing structure, and manage through government approval of each annual work program and budget, government approval of each award of a contract, government participation with a blocking vote on decisions, and regulation. There are similarities between royalty tax arrangements and production sharing arrangements, but there are also significant differences. For instance in each of the jurisdictions that the Administration compared to Alaska (e.g. Azerbaijan, Kazakhstan, Qatar, and Russia) the government has the ability to block decisions which it opposes

Set out on Annex 1 are comparisons of the Fiscal Contract to a generic production sharing contract.

FISCAL STABILITY:

The proved reserves of oil and gas on the Alaska North Slope ("ANS") have been known for many years and the expectation of large additional gas resources is high. The ANS oil reserves are being produced and brought to market and sold. However, the ANS gas reserves are being reinjected, and are not being brought to market and sold. Also, exploration for additional gas resources has been very limited. Arguably, ANS gas reserves have not been brought to market because to the Producers the value of the ANS gas reserves relative to the cost and risk of building a gas pipeline is not competitive with other projects in the Producers' portfolios. Although gas prices have increased in recent years, the Administration has determined in the FIF that under present market conditions the ANS gas resources are still stranded for the purposes of the SGDA.

The determination of whether the ANS gas reserves are in fact stranded for the purposes of the SGDA is a matter of policy for the State.

The goals of the SGDA are to cause Alaska's stranded gas to be developed without altering the tax and royalties on existing infrastructure and production, and to maximize the benefit to the State's citizens. To the end of obtaining commitments to achieve those goals, the SGDA empowers the State to make certain concessions to qualified persons. However, the underlying premise of the SGDA is that the State will receive commitments that will lead to development of stranded gas. The balancing of the certainty of the concessions given with the certainty of the commitments received is necessarily a matter of policy for the State.

The SGDA does not empower the State to make concessions for development of stranded oil reserves, much less oil reserves that under the existing lease structure and royalty / tax regime have been developed and are being produced and brought to market. Nonetheless, the Fiscal Contract provides for stabilization related to oil, and the Administration has proposed amendments to the SGDA to empower the State to grant stabilization for oil.

In the FIF the Administration argues that fiscal stabilization for oil is necessary because the lack of stabilization for oil would expose the Producers to the risk that in the future the State might change the fiscal regime for oil. The argument is tautological and not persuasive. Nonetheless, the fact remains that the Administration and the Producers have included stabilization for oil in the Fiscal Contract.

The determination of whether to amend the SGDA to empower the State to provide stabilization related to oil and whether the ANS oil reserves are in fact stranded for the purposes of the SGDA as amended are matters of policy for the State.

WORK COMMITMENT:

Assuming for the purposes of this summary that the State will determine that the ANS gas reserves are stranded, then the consideration for the State's concessions under the Fiscal Contract are the Producers' work commitments under the Fiscal Contract. The SGDA and the Fiscal Contract are structured on the implicit premises that because the cost and risk of building a gas pipeline are so high relative to the value of the gas reserves:

- it is not reasonable for the State to expect the Producers to make an unconditional commitment to build a gas pipeline from the ANS to Alberta ("Project") on the effective date; and
- it is reasonable for the State to expect the Producers to make a commitment to do the investigations and planning necessary to enable the Producers to get to the point where the Producers could decide whether to make a commitment to build the Project ("Project Sanction").

In Article 5 of the Fiscal Contract the "work commitment" is the undertaking by the Producers and their assignees ("Participants"):

- to begin the Project planning activities within 90 days after signing,
- to advance the Project planning activities with "Diligence", and
- to conclude the Project planning activities when the Participants have decided "whether to begin preparation of regulatory applications and planning for an Open Season".

The Fiscal Contract provides that the "Project planning activities" are described in the Qualified Project Plan ("QPP"), which in turn is defined to be section 5 of the Producers' SGDA application, which is apparently not publicly available. However, the Administration has summarized the QPP in the FIF and the Producers have prepared a Project Summary, both of which are publicly available. The QPP summarized in the FIF and the Producers' Project Summary are substantially similar but not identical.

The portions of the Project Summary that set out the activities precedent to a decision whether or not to make a commitment to build the Project are further summarized as follows:

1. During 2007 the Participants will conduct Project planning which consists of:
    (a) conducting additional technical studies to facilitate selection of a preliminary project design basis;
    (b) developing cost estimates and schedules for all project phases;
    (c) updating economic analyses;
    (d) preparing the work scope, staffing plan, and cost estimates for the next project phase;
    (e) selecting contractors for the next Project phase;
    (f) developing plans for access and regulatory/permit applications for both the US and Canada; and
    (g) establishing commercial structure and tariff principles to guide Project development.
2. During the second half of 2007 the Participants will begin the field data collection and Open Season processes;
3. During 2008 the Participants will complete the field data collection and Open Season processes, will begin the Front End Engineering Design (FEED) and the EIS / EIA permitting process, and will apply for the permits by the end of 2008; and
4. During 2009 and 2010 the Participants will continue the FEED and the EIS / EIA permitting process, and by the end of 2010 will make a decision whether or not to commit to construct the gas pipeline (Project Sanction).

The actual QPP may have more detailed Project planning activities than are set out in the Project Summary.

Taking the Article 5 together with the Project Summary leads to the conclusion that the actual "work commitment" under the Fiscal Contract is only the pre-planning activities set out above in items 1(a)-(g). The anticipated results from these pre-planning activities would fall well short of the information needed to make a decision whether to declare Project Sanction.

Article 5 contemplates that the Mainline Entity, which will be owned by the Participants, will amend the QPP at least annually. In the Fiscal Contract there are no limitations on the types of changes that could be made in an amended QPP. The Mainline Entity would have the right to change the scope of the work commitment and the timeline for performance of the work commitment in QPP at any time without State approval or consent.

If the State is not satisfied with the performance of the work commitment, then the State's sole remedy is to terminate the Fiscal Contract in accordance with Article 5. However, the termination process set out in Article 5 makes the State's ability to actually terminate the Fiscal Contract virtually impossible.

Article 5 provides that if the State gives notice of termination, any Participant may dispute the proposed termination and the dispute will be determined by arbitration. In the arbitration the legal presumption is that the Fiscal Contract will continue, the State's presumption of correctness and entitlement to deference is waived, and the State has the burden of proof to demonstrate:

- by "clear and convincing evidence" (not just a preponderance of the evidence)
- that the Participants are not acting with "prudence under the circumstances" in conducting the Project planning activities, and
- that the lack of such planning has resulted in a "material adverse impact on the

Project".

In making its decision the arbitral panel:

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

In summary the "work commitment" would not provide sufficient information to enable the Participants to make a decision whether to make a commitment to build the Project. The "work commitment" is in documents extraneous to the Fiscal Contract and may be modified in scope and time without the State's consent. The State's sole remedy for the participant's failure to perform the "work commitment" is termination of the Fiscal Contract, but the termination process is so draconian that the remedy is for all practical purposes unavailable. The determination of whether Article 5 in conjunction with the QPP provides a reasonable "work commitment" for the purposes of the Fiscal Contract and the SGDA are matters of policy for the State.

Possible solutions to create a more definitive "work commitment" consistent with the goals of the SGDA could be either (a) to amend the SGDA to require that any fiscal contract must, or (b) to recommend to the Administration that the Fiscal Contract must:

- set out in the body of the document the specific activities and the timeline to be performed in order to obtain the information necessary to decide whether to make a commitment to build a gas pipeline. An example might be the full description of activities in the QPP that are summarized in items 1-4 above;
- provide in the body of the document that specific milestones must be done by specified completion dates. An example might be the requirement to submit certain regulatory applications by the second anniversary of effective date, and to declare Project Sanction by the fourth anniversary of effective date;
- provide in the body of the document that the specific activities and the timeline comprising the "work commitment", and the milestones and corresponding completion dates, may not be changed without the State's consent; and
- provide in the body of the document that if a milestone is not achieved by its corresponding completion date the fiscal contract will terminate, unless the State in the exercise of its judgment consents to change the work milestone, or the specified completion date.

<u>STATE PARTICIPATION</u>:

Article 7 of the Fiscal Contract contemplates that the State will participate in the ownership of the various entities ("Project Entities") to be created to own and operate:

- various upstream transmission laterals between the lease or unit boundaries and the GTP ("Gas Transmission Pipelines");
- a gas treatment facility for removing CO_2 and other impurities ("GTP");
- a large diameter pipeline routed along TAPS line and the Alcan Highway to the Canada border ("Mainline");
- a large diameter pipeline from the Alaska border to Alberta ("Alaska to Alberta Project");
- a facility for extracting natural gas liquids ("NGL Plant"); and

- a large diameter pipeline from Alberta to the continental United States ("Alberta to Lower 48 Project").

The Fiscal Contract also contemplates that the State will create one or more entities:

- to hold the State's interest in the Project Entities; and
- to transport and sell the quantities of gas which the State is entitled to take in kind and to hold the State's capacity commitment in the Project ("State Capacity Holder").

Set out on Annex 2 is an example of one possible structure of the various entities and arrangements among the entities, which are relevant to the State's participation in the Project.

The boxes colored blue represent the State and the Producers' ultimate parent entities, the boxes colored orange represent the Producers, the boxes colored green represent the Producer's gas marketing affiliates and the area colored yellow represents the Fiscal Contract among the State and the Producers. These blue, orange and green boxes represent entities that exist, and the yellow area represents, to the extent of the Fiscal Contract, an arrangement among them that is known.

The boxes and areas on Annex 2 colored gray are contemplated by the Fiscal Contract and the Administration's presentations as being relevant to the State's participation in the Project. However, the entities in gray do not yet exist and the terms and conditions of the governance and other documents in gray and set out below are not known:

- the instruments creating the Project Entities and the various State entities;
- the governance agreements controlling the relationships among the interest holders and the management of each Project Entity;
- the operating agreements under which the business of each Project Entity will be conducted;
- the agreements coordinating the operations among the Project Entities;
- the ship-or-pay arrangements and marketing arrangements for the State's gas;
- the financing arrangements for the Project Entities and the State entities;
- the undertakings by the State and the Producers' parent companies concerning:
  - the financial guarantees for their respective subsidiaries; and
  - the coordination of the US and Canada regulatory processes.

The reason why the unknowns listed above are relevant to the State's participation is because they are needed to understand the governance of the Project Entities, the management and control of the Project, and the State's rights and obligations with respect to the Project.

- Once a State entity is established and staffed its directors and officers will be charged with accomplishing the business purposes of each such entity. As such they will no longer be fully aligned with the sovereign purposes of the State.
- In the absence of some supervening agreement the primary driver of each Project Entity will be the profitability of its business.
- In the absence of some governing instrument establishing that decisions of a Project Entity will be made by a super-majority or some regulation protecting the rights of minority interest holders, the State's ability to influence a decision of a Project Entity through its minority interest will be very limited.

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

Note that the SGDA (Sec. 43.82.220(a)(3)) provides that the State may:

> "... modify the timing and notice provisions of leases and unit agreements pertaining to the State's rights to receive its royalty in kind or in value if ...
>
> (2) certainty over time regarding the quantity of royalty gas the State may be taking in kind is needed to secure long term purchase and sale agreements;
>
> (3) the specified period of the State's commitment to take its royalty share in value or in kind does not exceed the term of the purchase and agreements; ..."

The implication of this provision of the SGDA is that if the State proposes to take its royalty share in kind then before a fiscal contract may become effective the State must know with certainty its rights and obligations with respect to its participation in the Project.

The determination of whether the State will take a participating interest in the Project and the terms and conditions under which the State will participate are matters of policy for the State.

Possible alternatives to have more certainty about the terms and conditions of the State participation could be either (a) to amend the SGDA to require that if State participation is proposed, then all documents reasonably related to the ownership, governance, management and control of the State's participation must be part of the submittal of any proposed fiscal contract, or (b) to recommend to the Administration that the approval of the Fiscal Contract will not be ripe for decision until all documents reasonably related to the ownership, governance, management and control of the State's participation are submitted.

REGULATORY REGIME:

Article 8 contemplates that the Participants and the State will endeavor to have the Federal Energy Regulatory Commission ("FERC") take jurisdiction of all components of the Project in Alaska: the Gas Transmission Pipeline, the GTP, the Mainline and any NGL Plant. However, FERC's jurisdiction over all components of the Project in Alaska is not certain. In the absence of FERC jurisdiction over any component in Alaska, the regulation of that component would ordinarily default to Alaska's public utility commission. However, Article 8.3 provides that:

> "If FERC does not assert jurisdiction [over the Project], no Party may seek or support the jurisdiction of the Regulatory Commission of Alaska ("RCA") over any aspect of the Project, including Project activities, operations, Facilities, or other matters ..."

In place of RCA jurisdiction for non-jurisdictional facilities the Participants must negotiate commercial arrangements. If despite the efforts of the State and the Participants to avoid the RCA, Article 8.3 also provides that

> "If the RCA asserts jurisdiction and takes actions inconsistent with principles of:
>
> (a) FERC policy for jurisdictional facilities; or
>
> (b) commercial agreements for non-jurisdictional facilities
>
> that result in a Loss to a Participant, the State shall reimburse that Participant for the Loss, which reimbursement could include cost of cover or transportation, or other appropriate relief. ..."

In its capacity as a sovereign the State is ordinarily entitled to deference and receives a presumption of correctness with respect to the interpretation of the State's regulations.

However, Article 19.10 provides that:

> "... the State's ... interpretation of a [constitution, statute, ordinance, tariff, convention, treaty, regulation, rule, order, or court rule or decision] ... is neither presumed correct nor entitled to deference."

For the avoidance of doubt that the State has waived its entitlement to deference in the interpretation of its laws and regulations, Article 38.3 provides that:

> "... no doctrine, rule, or principle of Law, tax Law, or equity that would create a presumption for or against, or deference to, the position of any Party applies in the interpretation of this Contract."

The Fiscal Contract is intended to be a broad and far reaching agreement. With regard to the effect of State participation on State laws and regulations Article 41.1 provides in part that:

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

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

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

To that end Article 41.2 provides that:

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

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

Note that the SGDA (Sec. 43.82.220(a)) contemplates that a fiscal contract may:

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

The SGDA does not appear to contemplate that any right, privilege or obligation of any Participant in all leases, agreements, regulations, rules orders and decrees would be modified to conform to a fiscal contract.

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

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

As noted by the Administration in its presentation, the arbitration provisions set out in Exhibit C are complex. Among other matters Exhibit C.8 (b) provides:

> "For purposes of Disputes under this Contract, the Parties waive any defense based

upon sovereignty, including immunity to arbitration, and immunity to judicial proceedings to enforce or aid any arbitration with respect to judicial proceedings as provided in Article 26.2."

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

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

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

The determination of whether and to what extent the State may be willing to suppress its regulatory regime is a matter of policy for the State.

QUALIFICATIONS AND LIMITATIONS:

This summary is based on a preliminary analysis of the FC Documents in light of general principles of law, which in our experience are normally applicable in transactions of the type contemplated by the FC Documents. This summary may not be deemed to be a representation as to any factual matters or an opinion of any legal conclusions under any specific jurisdiction.

This summary is a listing of some of our observations about the Fiscal Contract identified as of 23 May 2006 and no inference is intended nor should an inference be drawn that this summary is a comprehensive listing of all observations identified or that may be later identified. No conclusion of fact, opinion of law may be inferred or implied beyond the matters expressly set out above. We undertake no obligation to update or supplement this summary to reflect any changes in facts or law which occur after 23 May 2006, unless specifically requested to do so.

This summary is submitted at your request to bring to your attention certain matters which may of concern to you in your deliberations about the FC Documents. You may share this summary as you deem appropriate.

Very truly yours,
Barnes & Cascio LLP

ANNEX 1

	Alaska Fiscal Contract	Production Sharing Contract
Parties	• State, as entrepreneur and guarantor of AK-subs • AK-subs, as members of Project Entities • Producers and Project Entities, as Participants • No parent company or bank as guarantor of Participants	• Host Government, as regulator • NOC, as government entrepreneur • Local subsidiary or branch, as Investor • Parent company or bank, as guarantor of Investor
Area	• All of the Producers' ANS leases and units with right to add and remove plus Project right of way • Not ringfenced • Not subject to relinquishment	• Single block • Ringfenced by block • If Investor does not commit to develop during primary term, the PSC terminates and block is relinquished

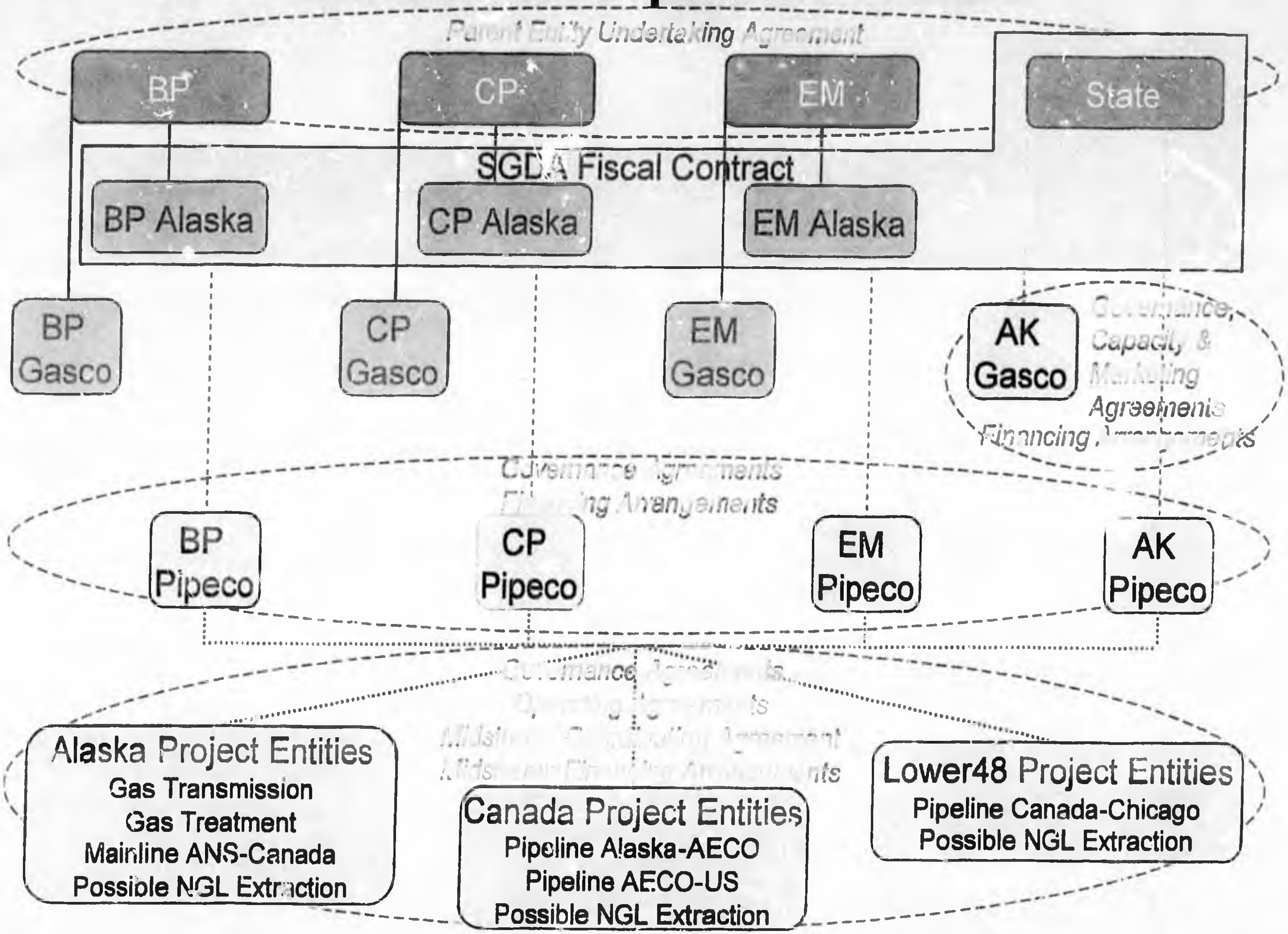
Term	• No primary term to perform QPP or commit to develop
	• If Mainline LLC declares Project Sanction
	  • 30 years for oil
	  • 45 years for gas
		• Primary term: 4-8 years to perform MWC and commit to develop
		• If Investor declares "commerciality and Host Gov't approves POD,
		  • 20-30 years for oil
		  • 30-45 years for gas

Work Commitment	• Participants must perform work commitment (e.g. pre-planning) • Participants may modify scope and timeline of work commitment • AK-subs role in decisions of Project Entities is not known • No State approval or consent is required • If State can prove Participants aren't acting with "Diligence", State's remedy is to terminate FC	• Investor must perform minimum work commitment • If Investors fail to do MWC during primary term, Host Gov't may terminate PSC and require Investors to pay minimum financial commitment • If Investor declares "commerciality" within primary term, then Investor must prepare POD, which is subject to Host Gov't approval • If Host Gov't approves POD, then Investor must develop per annual work program and budget approved by Host Gov't • If Investor fails to commit to develop during primary term, the Host Gov't may terminate PSC

Management and Control	• Neither State nor AK-subs participate in upstream decisions
	• AK-subs may participate in midstream decisions, extent is unknown
	• Try to limit Project regulation to only FERC / NEB
	• State reimburses for Loss resulting from RCA regulation
	• State waives its presumption of correctness
	• All disputes are resolved by arbitration
		• NOC participates in all upstream and midstream decisions and has blocking vote
		• Host Gov't fully regulates operations per local law
		• Host Gov't and NOC manage and control through
		  ◦ Approval of annual WP&B
		  ◦ Approval of contract awards
		  ◦ Approval of POD
		• Disputes are resolved by arbitration in a neutral forum

Government Take	• Royalty
	  ◦ RIK – AK Gasco takes gas not in marketable condition (gas + impurities) and pays gathering, treatment, transportation, marketing and disposal costs
	• Taxes
	  ◦ TIK – AK Gasco takes gas not in marketable condition (gas + impurities) and pays gathering, treatment, transportation, marketing and disposal costs
	  ◦ PILT's and other "Fiscal Obligations"
	• No local supply obligation
		• Royalty, either
		  ◦ RIV – world market price net of transportation costs, or
		  ◦ RIK – NOC takes oil and gas in marketable condition and pays transportation and marketing costs
		• Profit Share, either
		  ◦ PSIV – world market price net of transportation costs
		  ◦ PSIK – NOC takes oil and gas in marketable condition and pays transportation and marketing costs
		• Taxes
		• Local supply obligation and government right to requisition

Annex 2
Possible Gas Pipeline Structure



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MEMORANDUM June 1, 2006

SUBJECT: Difference between "long-term fiscal interest" and "best interest" of the state (HB 2004)

TO: Representative Jay Ramras
Co-Chair of the House Resources Committee
Attn: Jane Pierson

FROM: Dennis C. Bailey DCB
Legislative Counsel

HB 2004 changes the wording from an earlier version provided by the administration. The changes describe other terms that the commissioner may include in developing a contract. Page 3, line 25. The new version allows the commissioner to consider other terms and conditions that are in the "long-term fiscal interest of the state," changing the standard from the "best interest of the state." You requested an analysis of the difference of this change.

The Governor's transmittal letter for HB 2004 comments on the section broadening the terms that may be developed as follows:

> The bill would expand the types of terms that may be included in a contract. This is accomplished by a provision that would give the commissioner of the Department of Revenue broad discretion to adopt terms that are reasonable and promote the purposes of the SGDA.
>
> Terms are also appropriate if they are consistent with the long-term fiscal interests of the state. The authority granted would cover terms in the fiscal contract now under review by the Legislature and the public. These terms include "netting-out" provisions, payment of interest on obligations, ability to provide fiscal terms to others, confidentiality of payment-in-lieu records, state acquisition of pipeline capacity, indemnity given by the state, exemption from a reserves or resource tax, Regulatory Commission of Alaska jurisdiction, audits, and limits on damages.

AS 43.82.200 was enacted in 1998 by SCS CSHB 393(FIN), sec. 3, ch. 104 SLA 1998. Language identical to the existing language was included in the first draft of the bill, so the language does not appear to have been contentious. I was unable to find any discussion in the committee minutes concerning the best interest standard.

The general rule for interpreting statutory language is contained in AS 01.10.040.

> (a) Words and phrases shall be construed according to the rules of grammar and according to their common and approved usage. Technical words and phrases and those which have acquired a peculiar and appropriate meaning, whether by legislative definition or otherwise, shall be construed according to the peculiar and appropriate meaning.

In other words, unless words and phrases have acquired peculiar meaning by virtue of statutory definition or judicial construction, they have their ordinary meaning. *Lynch v. McCann*, 478 P.2d 835, 837 (Alaska 1970).

"Best interest of the state."
Alaska Statutes refer often to a finding of the best interest of the state but do not provide a special definition applicable to the Stranded Gas Development Act.

The Alaska Supreme Court has addressed interpretation of the "best interest" findings in the oil and gas context giving great deference to an agency finding as summarized by the following quote.

> . . . DNR's best interests determination and its determination that a project is consistent with the Alaska Coastal Management Plan's habitat standard are subject to a deferential reasonable basis review. n6 This standard properly reflects the fact that in these cases, DNR's determination "is almost entirely a policy decision, involving complex issues that are beyond this court's ability to decide. . . . This court has neither the authority nor competence to decide whether the public interest is 'best served' by a proposed disposition of land for offshore oil and gas exploration and development." n7
>
> -------------- Footnotes --------------
>
> n6 See *Trustees for Alaska v. State, Dep't of Natural Resources (Demarcation Point)*, 865 P.2d 745, 747 (Alaska 1993) ("DNR's best-interest determination is subject to deferential review by this court. Since the determination involves complex subject matter or fundamental policy formulations, this court reviews the decision only to the extent necessary to ascertain whether the decision has a reasonable basis.") (quoting *Trustees for Alaska v. State, Dep't of Natural Resources (Camden Bay I)*, 795 P.2d 805, 809 (Alaska 1990) (footnote, internal quotation marks and brackets omitted)); *Ninilchik*, 928 P.2d at 1213 ("This court's review [of DNR's consistency analysis] is limited to ensuring that DNR's decision was not arbitrary, capricious, or unreasonable." (internal quotation marks omitted)) (quoting *Trustees for Alaska v. State, Dep't of Natural Resources (Camden Bay II)*, 851 P.2d 1340, 1347 (Alaska 1993)).

> n7 *Hammond v. N. Slope Borough*, 645 P.2d 750, 758-59 (Alaska 1982) (internal brackets omitted) (quoting *Moore v. State*, 553 P.2d 8, 36 n.20 (Alaska 1976)). See also Ch. 38, § 1(2), SLA 1994 ("each determination under AS 38.05 that the interests of the state will be best served is a policy decision involving facts unique to each proposed disposal, and complex issues the analysis and resolution of which are most appropriately left to the expertise of the agency making the determination").

Kachemak Bay Conservation Soc'y v. Department of Natural Resources, 6 P.3d 270, 275 (Alaska 2000).

"Long-term fiscal interest of the state."
I was unable to find statutory or case law references to the concept of the "long-term fiscal interest of the state." Therefore, the ordinary meaning of the words applies.

Comments on changes.
Based on my research, although not exhaustive, neither the phrase "long-term fiscal interest" nor "best interest" appear to have special meaning by statutory definition or judicial interpretation. Therefore, the ordinary meaning of the words applies.

Changing the "best interest of the state to the "long-term fiscal" interest of the state seems to limit consideration to financial matters rather than other issues such as cultural or ecological. An argument could be made that other issues would often, if not always, have some effect on fiscal interests; however, the department might not be permitted to consider such indirect fiscal effects.

Generally, it seems that the changes to the SGDA are intended to broaden the powers of the commissioner to consider additional terms while developing a contract. However, the change from the more general "best interest of the state" to a more restrictive "long-term fiscal interest of the state" arguably limits the factors that may be considered by the department.

If I may be of further assistance, please advise.

DCB:med
06-397.med

2004

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OFFICE OF THE GOVERNOR
JUNEAU

May 31, 2006

The Honorable John Harris
Speaker of the House
Alaska State Legislature
State Capitol, Room 208
Juneau, AK 99801-1182

Dear Speaker Harris:

Under the authority of art. III, sec. 18, of the Alaska Constitution, I am transmitting a bill amending the Alaska Stranded Gas Development Act (AS 43.82) (SGDA) to clarify or provide additional authority for the development of stranded gas fiscal contract terms.

When the SGDA was originally passed in 1998, the Legislature had in mind a very different kind of state involvement than is presently written into the proposed fiscal contract now under preliminary review by the Legislature. The original intent was to authorize the development of a contract that could reduce the tax burdens on a project. Under the proposed fiscal contract, the state would become a part owner of a large-diameter gas pipeline with a design capacity to transport approximately 4 billion cubic feet per day of stranded gas from the Alaska North Slope to markets in Canada and the Lower 48 states. The proposed fiscal contract would create obligations to make payments in lieu of taxes that are roughly equivalent to the taxes in effect for the 2005 tax period.

After analysis of the economics of the project, it was determined by the state that the best method for inducing the sponsor group to proceed with development was for the state to agree to take an ownership interest and to agree to assume financial responsibility for shipping its gas through the pipeline. It was also considered important that each owner's interest in the project should correspond to the amount of the owner's gas that would be shipped through the pipeline. By taking payment of certain tax obligations in gas rather than money, the state could establish an ownership interest of approximately 20 percent. These key terms would increase the potential profitability of the project in a way that would not require the state to materially reduce public revenue in the future.

The legislative history of the SGDA was clear that the original intent was to provide fiscal certainty only on gas taxes. The sponsor group made a compelling argument that fiscal certainty must extend to taxes on oil as well as on gas. The production of oil goes hand in hand with the production of gas. Because of this connection, any fiscal constraints placed on the exploration or development for oil also have a direct effect on the exploration and development of gas. For this and other reasons, it was agreed that fiscal certainty should be extended to taxes applicable to oil production.

The amendments proposed in this bill are intended to provide express authority in the SGDA for the terms in the proposed fiscal contract. To accomplish this intent, the bill would broaden the scope of the purposes of the SGDA to include fiscal terms relating to oil as well as to gas. The fiscal terms would also extend to a related party, which may include the mainline entity formed to own and operate the gas pipeline and related facilities.

The bill would broaden the scope of subjects that may be negotiated under the SGDA. These new subjects include equity ownership, payment of obligations in gas rather than money, and changes in existing leases and other agreements with the state regarding oil and gas properties.

The bill would expand the types of terms that may be included in a contract. This is accomplished by a provision that would give the commissioner of the Department of Revenue broad discretion to adopt terms that are reasonable and promote the purposes of the SGDA. Terms are also appropriate if they are consistent with the long-term fiscal interests of the state. The authority granted would cover terms in the fiscal contract now under review by the Legislature and the public. These terms include "netting-out" provisions, payment of interest on obligations, ability to provide fiscal terms to others, confidentiality of payment-in-lieu records, state acquisition of pipeline capacity, indemnity given by the state, exemption from a reserves or resource tax, Regulatory Commission of Alaska jurisdiction, audits, and limits on damages.

The bill would expand the scope of authority to adopt contract terms that modify existing law set out in AS 38 concerning oil and gas property. Under existing law, authority extends only to timing and notice requirements applicable to royalties. The bill includes provisions to allow broader powers to adopt terms resolving conflicts between the terms of the contract and provisions in existing oil and gas leases and unit agreements. Under the bill, the terms of the contract prevail over contrary provisions in state leases or unit agreements.

The bill would place a limit of 45 years on the expected term of the contract from the effective date. It is expected that it will take approximately 10 years from the effective date to achieve commencement of commercial operations. Existing law provides that the term is 35 years from the commencement of commercial operations. The bill also authorizes the contract to provide for a suspension of the running of the term during periods of force majeure.

The bill would provide interim authority for the commissioner of the Department of Revenue to negotiate collateral agreements to form limited liability companies, limited liability partnerships, or any other recognized form of business association that would own or operate any part of the project.

The bill would create an account in the general fund to receive municipal impact payments from the sponsor group and also a fund into which the money will be subsequently appropriated by the Legislature. Once in the fund, the money will be available for grants to economically affected municipalities and certain nonprofit organizations serving the unorganized borough; the grants would be administered by the Department of Commerce, Community, and Economic Development.

I urge your prompt and favorable consideration of this bill.

Sincerely yours,

Frank H. Murkowski
Governor

Enclosure

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MEMORANDUM June 4, 2006

SUBJECT: Comments on CSHB 2004(RES) (Work Order No. 24-GH2046\G)

TO: Representative Ralph Samuels
Representative Jay Ramras,
Co-Chairs of the House Resources Committee
Attn: Jim Pound

FROM: Dennis C. Bailey DCB
Legislative Counsel

Please note the following concerns with CSHB 2004(RES).

Amendment #3 (Samuels) had a handwritten modification that we could not decipher, so the handwritten portion was omitted. This issue will have to be addressed in a subsequent version of the bill.

We have modified the new language in AS 43.82.437(a)(15) from the conceptual amendment for consistency making it an Operating Agreement Requirement. Please confirm that the intent has not changed.

I expect that you are already aware of the broader outstanding issue of whether requiring legislative approval of executive action infringes on executive power under the separation of power doctrine.

If I may be of further assistance, please advise.

DCB:lmb
06-189.lmb

Enclosure

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MEMORANDUM June 1, 2006

SUBJECT: Sectional summary (HB 2004, Work Order No. 24-GH2046\A)

TO: Representative Jay Ramras
Attn: Jim Pound

FROM: Dennis C. Bailey DCB
Legislative Counsel

You have requested a sectional summary of the above-described bill. As a preliminary matter, note that a sectional summary of a bill should not be considered an authoritative interpretation of the bill and the bill itself is the best statement of its contents. Also note that although HB 2004 has the same version identifier, 24-GH2046\A, the version is not the same as the version included in the governors fiscal findings accompanying the contract. I have noted the changes from the prior version in brackets { }.

I have summarized the proposed changes to the Stranded Gas Development Act, not the entire Act.

Section 1. Amends the chapter's purpose statement by removing the prohibition for alteration of taxes and royalties, instead allowing fiscal terms related to oil and tax agreements and taxes, including oil and gas production taxes, income taxes and property taxes. {New version omits reference to royalties.}

Makes fiscal terms applicable to "a related party," as well as the existing "sponsor" or "sponsor group."

Section 2. Modifies the catch line removing references to payment in lieu of taxes and royalty adjustments.

Allows negotiation of payment in lieu of taxes with "a related party." Removes the condition that the negotiation be as a consequence of participation in a qualified project.

Permits negotiation of oil and gas lease agreements unit agreements and other agreements. {Omits reference to royalty.}

Permits negotiation of gas production tax or payment in lieu of taxes by delivery of gas.

Permits negotiation of state ownership in the subject of the contract and state ownership related to collateral agreements under new sec. 43.82.437.

Section 3. Allows the commissioner of revenue to develop new terms relating to
(1) modification of oil and gas taxes, {Removes reference to production, income and property taxes.}
(2) credits for investments in a project, and
(3) oil and gas leases, unit agreements, and other agreements under AS 38.
{Removes several sections noting other negotiable terms.}

Rewords the authority of the commissioner to negotiate other terms and conditions that are reasonable and promote {rather than "necessary to further"} the purpose of the chapter including implementation of the Stranded Gas Development Act or in the long-term fiscal interest {rather than "best" interest"} of the state.

Section 4. Adds new subsection allowing contract terms for arbitration and alternate dispute resolution that may provide for a waiver of the state's immunity with the concurrence of the attorney general, including waiver of sovereign immunity, consent and entrance and enforcement of an arbitration award in any state court in the United States that has jurisdiction over the state, but only after it is entered and enforcement sought in the superior court of the state. {New section.}

Section 5. Adds "related party" in addition to qualified sponsors or groups with whom the commissioner may develop proposed terms for periodic payment in lieu of specified taxes.

For the purpose of listing specific taxes for which the commissioner may negotiate payments in lieu of taxes. {Removes language specifically including within state and municipal taxes the following: (1) taxes on oil and gas reserves or resource, (2) taxes not authorized or imposed by the state or a municipality at the time a contract takes effect, and (3) taxes enacted by initiative.}

Section 6. Excludes contrary provisions in regulations under AS 38 (Public Lands).

Eliminates the requirement that the commissioner of natural resources develop regulations with the concurrence of the affected parties holding a state lease or unit agreement unless necessary.

Broadens the topic for developing terms by eliminating a "timing and notice" restriction and by allowing terms related to other agreements under AS 38 as well as the existing "oil and gas leases and unit agreements."

Allows the commissioner of natural resources, with the concurrence of the commissioner of revenue, to develop terms modifying oil and gas leases, unit agreements, and other agreements pertaining to the state's rights to receive royalty on gas in kind or in value (1) if the viability of the project depends on long term shipping commitments, or if the certainty regarding the royalty gas the state may be taking over time is needed to enter into shipping commitments or marketing agreements, and (2) the modification doesn't impair the project or the state from meeting foreseeable instate gas needs.

Deletes reference to "purchase and sale agreements" and "securing the purchase and sale agreement." Deletes the requirement that the state's commitment to take royalty gas in value or in kind may not exceed the duration of the purchase and sale agreement.

In addition the commissioner of natural resources may develop terms pertaining to the state's right to receive royalties in kind or in value relating to lease or unit expenses for separation, cleaning, dehydration, gathering, salt water disposal and preparation for transportation on or off the lease.

Section 7. Removes the restriction that the commissioner of revenue include references only to royalties.

Section 8. Exempts from AS 38, or regulations under AS 38, an agreement to take royalty in kind that satisfies AS 43.82.220(a)(1)(A) - (C).

Section 9. Removes the restriction on the duration of the contract that it be "no longer than is necessary to develop the stranded gas that is subject to the contract" but leaves in place the period of 35 years from the commencement of commercial operations, excluding suspensions of contract obligations covered by force majeure. However, the term may not exceed 45 years from the effective date of the contract.

{Omits the addition to AS 43.82.270(b) allowing the addition of new parties to the contract.}

Section 10. Provides that the contract must include provisions for implementing the project plan that "may be modified as a result of the development of a contract . . . ."

Section 11. Authorizes the commissioner of revenue with the concurrence of the commissioner of natural resources to negotiate collateral agreements required to implement the state's ownership interest in the project. The authority to negotiate collateral agreements lapses 180 days after the effective date of the law approving the contract. {omits references to "entering" into collateral agreements}{extends the time the commissioner may enter collateral agreements from 60 to 180 days after the effective date of the law approving the contract}

A collateral agreement negotiated by the commissioner on behalf of the public corporation authorized to acquire an ownership interest in the project may be executed and implemented by the directors of the public corporation. The commissioner members of the board are a quorum for the first 120 days after the public corporation is established. During that time the unanimous vote of the commissioners is required for action but if a public member has been appointed, the vote required for action is a majority vote. {Changes provisions allowing the commissioner to negotiate and enter collateral agreements before the public corporation is formed.}

A collateral agreement executed by the members of the board of the public corporation binds only the public corporation and does not make the state a party to the collateral agreement. {Changes execution by the commissioner to execution by the members of the public corporation board.}

Except as provided by AS 43.82.437, and the confidential provisions of AS 43.82.310, a collateral agreement that has been authorized by the legislature is not subject to any of the provisions of this chapter.

A "collateral agreement" includes an agreement between the state or a state entity and a qualified sponsor or sponsor group or their affiliate to form limited liability companies, limited liability partnerships, or any other recognized form of business association to own or operate any portion of the project.

{Eliminates former sec. 12 amendments related to administrative termination. The remainder of AS 43.82.445 is repealed under sec. 18.}

Section 12. If the contract exempts a sponsor, a member of a sponsor group, or a related party from municipal property tax, the commissioner shall provide a term that provides for payment to a municipality affected by the exemption but not necessarily, as previously, from "a party."

Section 13. Provides that if a contract affects municipalities, the commissioner shall include a term in the contract for periodic impact payments to the state that may be appropriated to the Alaska Natural Gas Pipeline Construction Impact Fund established by AS 43.82.505(c) (see sec. 14) for the benefit of affected municipalities.

Section 14. Establishes the Alaska Natural Gas Pipeline Construction Impact Fund in the Department of Commerce, Community, and Economic Development {formerly Department of Revenue} to address the economic and social impacts incurred by a municipality, or a nonprofit organization serving the unorganized borough {added provision for nonprofit} during construction of a project.

Allows DCCED to adopt regulations for applications for grants to alleviate pipeline impacts. Priority given to most direct or severe impact. The Department shall finance grants to the extent money is available in the impact fund. The department shall provide a list of qualified grantees to the legislature with a recommendation. The commissioner of DCCED shall consult with the municipal advisory groups in determining whether an expenditure is eligible for a grant and in allocating money among grant proposals. {New sections.}

Grant money may not be used to retire municipal debt. Impact funds do not lapse. Disclaims dedication of money for a specific purpose.

The requirements of the Executive Budget Act, AS 37.07, apply to money in the fund.

Section 15. Terminates the municipal advisory group 90 days after the final distribution of impact money or the commencement of operation of the project.

{Former sec. 16 related to appropriation of impact payment money is omitted.}

{Former sec. 17 related to issuance of exemptions certificates is omitted.}

Section 16. Defines "related party" as a limited liability company or similar entity that is affiliated with a qualified sponsor or qualified sponsor group that owns or operates a qualified project or project segment, and is an intended beneficiary of the fiscal terms included in a contract.

Section 17. Creates an exception to the statutory arbitration provisions of AS 09.43.300 - 09.43.595, apparently allowing arbitration as provided in a contract term.

Section 18. Entirely repeals AS 43.82.445 related to administrative termination of the contract. {Formerly repealed only sections b-d}

Section 19. Modifies the catch line for AS 43.82.220 "Contract terms relating to royalty," to include oil and gas leases and other agreements.

Section 20. Makes sections 1 - 12, 15, 16, and 18 of the Act retroactive to January 1, 2004 and sec. 17 retroactive to January 1, 2005.

Section 21. Gives the bill an immediate effective date.

Although you requested an opinion of how the proposed changes to the Stranded Gas Development Act affect the proposed gas line contract, the magnitude of the request is beyond the time available and beyond my expertise. Generally though, the intent of the proposed changes to the act appear to be motivated to allow the negotiation that has occurred developing the proposed contract. If I may be of further assistance, please advise.

DCB:lmb
06-178.lmb

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June 2, 2006

The Honorable Ralph Samuels
Alaska State Representative
State Capitol, Room
Juneau, AK 99801-1182

Dear Representative Samuels:

This letter contains the questions posed during yesterday's House Resources Committee's hearing on the Stranded Gas Development Act Amendments (HB 2004) and the corresponding answers.

1. What are the terms of members of a Municipal Advisory Group (MAG)?

Representatives are appointed to a MAG by the mayor of a municipality. AS 43.82.510(b). State law does not prescribe a term for the representatives. The SGDA does require that a MAG itself is to serve only until final action is taken on the application for which the group was appointed. AS 43.82.510(c).

Section 15 of HB 2004 will amend the law to provide that the MAG serves until the final distribution of impact payment money or until commencement of commercial operations.

2. Whether a tax rate incorporated into a payment in lieu of tax provision of a contract ratified by the legislature can be later modified by mutual agreement of the parties.

This administration does not view the fiscal contract as allowing for any material amendments to the tax related provisions.

However, after careful review of the contract, we believe there is an argument that such an amendment is, at least theoretically, possible. Article 39.1 allows the contract to be amended in writing by mutual agreement of the parties.

To avoid there being such an issue, the legislature could consider amending AS 43.82.435 by adding: "A contract authorized by this section and executed by the Governor may contain provisions that provide for amendment of contract terms without further action by the legislature except that any term relating to taxes described in AS 43.82.210(a), or payments in lieu of such taxes, may not be amended without further legislative authorization under this section."

3. The proposed amendments to AS 43.82.020, in Sec. 2 of HB 2004, authorize the commissioner to negotiate terms for inclusion in a proposed contract for certain adjustments regarding oil and gas lease agreements, unit agreements and other agreements. What are some examples of modification of lease and unit agreements?

The proposed contract provisions (1) redefine upstream royalty responsibilities of the state with respect to payment of gas-related field costs such as cleaning, gathering, treating, and dehydration; (2) assign responsibility to the state for conditioning of royalty gas and disposal of impurities associated with the conditioning of that gas; (3) limit over the term of the contract the state's ability to switch between royalty in kind and royalty in value; (4) define points of delivery for royalty gas; (5) assign responsibility for downstream NGL extraction; and (6) provide an optional alternative royalty rate for certain sliding scale royalty leases.

The contract also contains provisions that amend the requirements for the Point Thomson Unit lessees to submit further plans of development and establishes certain work commitments for the Point Thomson Unit lessees.

4. The issue of Section 6(c) of HB 2004, 43.82.220(1)(c), and ramp up of local gas use--

Many questions were raised concerning the availability of gas for in-state use. The amendments to the Stranded Gas Act are intended to ensure the State has the necessary authority to provide opportunities for in state gas use.

We will have FERC counsel from Morrison Foerster available telephonically to respond to these questions and discuss opportunities for in state gas use under the contract.

5. Compare the case law relating to *"in best interests of the state"* to *"in the long-term fiscal interests of the state"*?

AS 43.82.200 sets standards under which the commissioner of Revenue may develop a contract under the Alaska Stranded Gas Development Act. Under current law, the commissioner may include terms or conditions "necessary to further the purposes of [AS 43.82]; or in the best interests of the state."

Once a contract is developed, before the commissioner presents his preliminary and final findings and determinations to the legislature, he must determine that the contract terms are "in the long-term fiscal interests of the state." AS 43.82.400(a); AS 43.82.430(b).

In our view, having a standard to be met for developing contract terms that is potentially different that the standard necessary to be met for forwarding contract terms is ambiguous and confusing. To date, we have not been able to find any legislative history on the SGDA that discusses why there are different standards for contract terms contained in the act.

It is difficult to describe precisely the practical difference between the standards because the standard "long-term fiscal interests of the state" neither appears elsewhere in Alaska statutes nor has it been interpreted by the Alaska Supreme Court.

The standard "in the best interests of the state," however, does appear in statute and has been interpreted numerous times by the Alaska Supreme Court. The statute most analogous to the SGDA is probably AS 38.05.035(e). Under that statute, the commissioner of Natural Resources may approve contracts for sale, leases or disposals of state land "upon written findings that the interests of the state will be best served."

The Alaska Supreme Court has found that this standard can be traced to Art. VIII, of the Alaska Constitution. Art. VIII, sec. 1 says that "[i]t is policy of the State to encourage . . . the development of its resources by making them available for maximum use consistent with the public interest." In turn, sec. 2 of Art. VIII authorizes the legislature to provide for the utilization, development, and conservation of all natural resources belonging to the state . . . for the maximum benefit of its people." *Kachemak Bay Conservation Society v. State, Department of Natural Resources,* 6 P.3d 270, 276 (Alaska 2000).

In our view, the standard "long-term fiscal interests of the state" would probably be traced to the same constitutional provisions as the "best interest standard" described above, although it may be a somewhat narrower test than "best interests of the state."

This is because a "long-term fiscal interests of the state" standard focuses on fiscal interests (although it should be noted that the Stranded Gas Development Act requires the commissioner to consider factors such as safe management and operation of the project, mitigation of increased demand for public services. AS 43.82.120(b)), while a "best interests of the state" standard is, arguably, broader.

Because the Stranded Gas Development Act deals primarily with fiscal issues, the "long-term fiscal interest of the state" standard is arguably more relevant and in keeping with the purposes of the Act.

Again, including two distinct standards in the Stranded Gas Development Act raises the issue of why the legislature chose to include a "in the best interest of the state" standard for terms and conditions in AS 43.82.200 and a "long-term fiscal interests of the state in AS 43.82.400 and AS 43.82.430 since all three sections deal with the development of the same contract. There appears to be no particular reason in either the legislative history or from a reading of the rest of the Stranded Gas Development Act. The language change proposed in section 3 of SB 2004 will merely insure that a court considers the commissioners' proposed contract terms and preliminary and final findings under the same standards.

6. Could state law be amended to impose a tax on limited liability companies (LLC) owning a portion of the project?

Under Article 11.1 of the fiscal contract, participant's interests are exempt from taxation except for income tax PILT (SCIT) set forth in Article 19 of the fiscal contract, which is limited to the law in effect as of October 1,2005. If the state were to impose a general income tax on LLCs it is unlikely under the terms of the contract that it could be made to apply to the LLCs that are midstream entities under the terms of the contract.

The members of the LLCs which would be affiliates of the producers would pay corporate income tax under the terms of Article 19 as part of the unitary business of the producer.

In accordance with Article 31.1(b) an assignee of a membership interest in an LLC, that is not an affiliate of a producer, would not receive fiscal certainty with regard to corporate income tax.

We hope this answers the committee's questions.

Sincerely,

Kevin Jardell
Legislative Director

Cc: Representative James Elkins
Representative Carl Gatto
Representative Gabrielle LeDoux
Representative Kurt Olson
Representative Paul Seaton
Representative Harry Crawford
Representative Mary Kapsner

STATE OF ALASKA

DEPARTMENT OF REVENUE

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January 23, 2004

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Re: Application under the Alaska Stranded Gas Development Act

Dear Gentlemen:

ConocoPhillips Alaska Inc., BP Exploration (Alaska), Inc., and ExxonMobil Alaska Production, Inc. (the "Sponsors") have submitted an application and proposed project plan to the State under the Stranded Gas Development Act for a pipeline that would transport natural gas from the Alaska North Slope through Alaska to markets in Canada and the Lower 48 United States.

The Sponsors' application identifies two of the possible routes to bring Alaska North Slope stranded gas resources to market. One route would generally follow the TAPS route and then the Alaska Canadian highway through Canada and into Alberta (the Highway Route). The second pipeline route would cross state land in or adjacent to the

Letter re: Application

Beaufort Sea off the north coast of Alaska and then proceed east to the Mackenzie River valley and south to Alberta (the Over-the-Top Route).

Both the Over-the-Top Route and the Highway Route are potentially qualified projects under the Stranded Gas Development Act. Nevertheless, the Over-the-Top Route is inconsistent with current state law. The Right-of-Way Leasing Act currently prohibits the Department of Natural Resources from issuing a lease across state land for the Over-the-Top Route (AS 38.35.017).

The State has reviewed the materials submitted by the Sponsors and finds that the Sponsors are qualified sponsors under the Act and that the application and proposed project plan are sufficient under the Act. Therefore the State hereby approves the Sponsors' application and proposed project plan. The State acknowledges that no final commercial decision has been made on any route and the State intends to fully discuss all aspects of the permitable, qualified project consistent with the application submission. The State intends to negotiate with the Sponsors concerning all aspects of the application and proposed project plan.

The State looks forward to the next stage of the process and working with the Sponsors to develop a mutually acceptable contract.

STATE OF ALASKA
DEPARTMENT OF REVENUE

William A. Corbua

William A. Corbua, Commissioner

STATE OF ALASKA
DEPARTMENT OF NATURAL RESOURCES

Tom Irwin, Commissioner

cc: Governor Frank H. Murkowski
James F. Clark, Chief of Staff
Gregg D. Renkes, Attorney General

Chapter 43.82. ALASKA STRANDED GAS DEVELOPMENT ACT

Article 01. CONTRACTS FOR PAYMENTS IN LIEU OF OTHER TAXES

Sec. 43.82.010. Purpose.

The purpose of this chapter is to

(1) encourage new investment to develop the state's stranded gas resources by authorizing establishment of fiscal terms related to that new investment without significantly altering tax and royalty methodologies and rates on existing oil and gas infrastructure and production;

(2) allow the fiscal terms applicable to a qualified sponsor or the members of a qualified sponsor group, with respect to a qualified project, to be tailored to the particular economic conditions of the project and to establish those fiscal terms in advance with as much certainty as the Constitution of the State of Alaska allows; and

(3) maximize the benefit to the people of the state of the development of the state's stranded gas resources.

Sec. 43.82.020. Contracts for payments in lieu of other taxes and for royalty adjustments.

The commissioner may, under this chapter, negotiate terms for inclusion in a proposed contract with a qualified sponsor or qualified sponsor group providing for

(1) periodic payment in lieu of one or more taxes that otherwise would be imposed by the state or a municipality on the qualified sponsor or members of the qualified sponsor group as a consequence of the sponsor's or group's participation in an approved qualified project under this chapter; and

(2) certain adjustments regarding royalty under AS 43.82.220.

Article 02. QUALIFICATION AND APPLICATION PROCEDURES

Sec. 43.82.100. Qualified project.

Based on information available to the commissioner, the commissioner may determine that a proposal for new investment is a qualified project under this chapter if the project

(1) principally involves

(A) the transportation of natural gas by pipeline to one or more markets, together with any associated processing or treatment;

(B) the export of liquefied natural gas from the state to one or more other states or countries; or

(C) any other technology that commercializes the shipment of natural gas within the state or from the state to one or more other states or countries;

(2) would produce at least 500,000,000,000 cubic feet of stranded gas within 20 years from the commencement of commercial operations; and

(3) is capable, subject to applicable commercial regulation and technical and economic considerations, of making gas available to meet the reasonably foreseeable demand in this state for gas within the economic proximity of the project.

Sec. 43.82.110. Qualified sponsor or qualified sponsor group.

The commissioner may determine that a person or group is a qualified sponsor or qualified sponsor group if the person or a member of the group

(1) intends to own an equity interest in a qualified project, intends to commit gas that it owns to a qualified project, or holds the permits that the department determines are essential to construct and operate a qualified project; and

(2) meets one or more of the following criteria:

(A) owns a working interest in at least 10 percent of the stranded gas proposed to be developed by a qualified project;

(B) has the right to purchase at least 10 percent of the stranded gas proposed to be developed by a qualified project;

(C) has the right to acquire, control, or market at least 10 percent of the stranded gas proposed to be developed by a qualified project;

(D) has a net worth equal to at least 10 percent of the estimated cost of constructing a qualified project;

(E) has an unused line of credit equal to at least 15 percent of the estimated cost of constructing a qualified project.

Sec. 43.82.120. Applications.

(a) A qualified sponsor or qualified sponsor group may submit to the department an application for development of a contract under AS 43.82.020 evidencing that the requirements of AS 43.82.100 and 43.82.110 are met. The application must be submitted in the manner and form and contain the information required by the department.

(b) Along with an application submitted under (a) of this section, an applicant shall submit a proposed project plan for a qualified project that contains the following information based on the information known to the applicant at the time of application:

(1) a description of the work accomplished as of the date of the application to further the project;

(2) a schedule of proposed development activity leading to the projected commencement of commercial operations of the project;

(3) a description of the development activity proposed to be accomplished under the proposed project plan;

(4) a description of each lease or property that the applicant believes to contain the stranded gas that would be developed if the project was built;

(5) a description of the methods and terms under which the applicant is prepared to make gas available to meet the reasonably foreseeable demand in this state for gas within the economic proximity of the project during the term of the proposed contract, including proposed pipeline transportation and expansion rules if pipeline transportation is a part of the proposed project;

(6) a detailed description of options to mitigate the increased demand for public services and other negative effects caused by the project;

(7) a detailed description of options for the safe management and operation of the project once it is constructed;

(8) other information that the commissioner of revenue, in consultation with the commissioner of natural resources, considers necessary to make a determination that

(A) the work accomplished as of the date of application, the schedule of proposed development activity, and the development activity proposed to be accomplished under the proposed project plan reflect a proposal for diligent development on the part of the applicant;

(B) the proposed project plan does not materially conflict with the obligations of a lessee to the state under a lease or under a pool, unit, or other agreement with the state; and

(C) the proposed project plan describes satisfactory methods and terms for accommodating reasonably foreseeable demand for gas in this state within the economic proximity of the project during the term of the proposed contract.

(c) The requirements of (b) of this section do not diminish the obligations of a qualified sponsor or member of a qualified sponsor group to the state or restrict the authority of the commissioner of revenue or the commissioner of natural resources under any other law or agreement relating to a plan of development for a lease, pool, or unit.

Sec. 43.82.130. Qualified project plan.

A proposed project plan submitted under AS 43.82.120 may be approved as a qualified project plan under AS 43.82.140 if the proposed project plan

(1) reflects a proposal for diligent development of the project on the part of the applicant;

(2) does not materially conflict with the obligations of a lessee to the state under a lease or under a pool, unit, or other agreement with the state; and

(3) describes satisfactory methods and terms for making gas available to meet the reasonably foreseeable demand in this state for gas within the economic proximity of the project during the term of the proposed contract.

Sec. 43.82.140. Review of applications and determination of qualifications.

(a) The commissioner shall review an application submitted under AS 43.82.120 to determine whether the provisions of AS 43.82.100 concerning a qualified project and AS 43.82.110 concerning a qualified sponsor or qualified sponsor group have been met. The commissioner may approve an application only if those provisions have been met.

(b) If the commissioner approves an application under (a) of this section, the commissioner and the commissioner of natural resources shall review the proposed project plan submitted with the application to determine whether the provisions of AS 43.82.130 have been met. The commissioner may approve the proposed project plan as a qualified project plan only if the commissioner of natural resources concurs in the approval.

(c) The commissioner shall send to the applicant written notice of and the reasons for the determinations made under (a) and (b) of this section.

Sec. 43.82.150. Actions challenging determinations on applications.

(a) Only an applicant under AS 43.82.120 who is aggrieved by a determination of the commissioner of revenue or the commissioner of natural resources under AS 43.82.140 may seek judicial review of the determination.

(b) The only grounds for judicial review of a determination made under AS 43.82.140 are

(1) failure to follow the qualification and application procedures set out in AS 43.82.100 - 43.82.180; or

(2) abuse of discretion that is so capricious, arbitrary, or confiscatory as to constitute a denial of due process.

Sec. 43.82.160. Multiple applications for similar or competing qualified projects.

Nothing in this chapter prohibits different qualified sponsors or different qualified sponsor groups from submitting applications under AS 43.82.120 relating to similar or competing qualified projects or prohibits the commissioner of revenue or the commissioner of natural resources from reviewing and approving applications and proposed project plans under AS 43.82.140 relating to similar or competing qualified projects.

Sec. 43.82.170. Application deadline.

The commissioner of revenue or the commissioner of natural resources may not act on an application for a contract submitted under AS 43.82.120 unless the application is received by the Department of Revenue no later than March 31, 2005.

Sec. 43.82.180. Withdrawal of applications.

Subject to the terms of a reimbursement agreement under AS 43.82.240 or other agreement with the Department of Revenue, the Department of Natural Resources, the commissioner of revenue, or the commissioner of natural resources affecting the withdrawal of an application, a qualified sponsor or qualified sponsor group may withdraw an application submitted under AS 43.82.120 at any time before the date that the commissioner of revenue submits a contract to the governor under AS 43.82.430 without further obligation under this chapter.

Article 03. CONTRACT DEVELOPMENT

Sec. 43.82.200. Contract development.

If the commissioner approves an application and proposed project plan under AS 43.82.140, the commissioner may develop a contract that may include

(1) terms concerning periodic payment in lieu of one or more taxes as provided in AS 43.82.210;

(2) terms developed under AS 43.82.220 relating to

(A) timing and notice of the state's right to take royalty in kind or in value; and

(B) royalty value;

(3) terms regarding the hiring of Alaska residents and contracting with Alaska businesses under AS 43.82.230;

(4) terms regarding periodic payment to, or an equity or other interest in a project for, municipalities under AS 43.82.500;

(5) terms regarding arbitration or alternative dispute resolution procedures;

(6) terms and conditions for administrative termination of a contract under AS 43.82.445; and

(7) other terms or conditions that are

(A) necessary to further the purposes of this chapter; or

(B) in the best interests of the state.

Sec. 43.82.210. Contract terms relating to payment in lieu of one or more taxes.

(a) If the commissioner approves an application and proposed project plan under AS 43.82.140, the commissioner may develop proposed terms for inclusion in a contract under AS 43.82.020 for periodic payment in lieu of one or more of the following taxes that otherwise would be imposed by the state or a municipality on the qualified sponsor or member of a qualified sponsor group as a consequence of participating in an approved qualified project:

(1) oil and gas production taxes and oil surcharges under AS 43.55;

(2) oil and gas exploration, production, and pipeline transportation property taxes under AS 43.56;

(3) *[Repealed, Sec. 6 ch 34 SLA 1999].*

(4) Alaska net income tax under AS 43.20;

(5) municipal sales and use tax under AS 29.45.650 - 29.45.710;

(6) municipal property tax under AS 29.45.010 - 29.45.250 or 29.45.550 - 29.45.600;

(7) municipal special assessments under AS 29.46;

(8) a comparable tax or levy imposed by the state or a municipality after June 18, 1998;

(9) other state or municipal taxes or categories of taxes identified by the commissioner.

(b) If the commissioner chooses to develop proposed terms under (a) of this section, the commissioner shall, if practicable and consistent with the long-term fiscal interests of the state, develop the terms in a manner that attempts to balance the following principles:

(1) the terms should, in conjunction with other factors such as cost reduction of the project, cost overrun risk reduction of the project, increased fiscal certainty, and successful marketing, improve the competitiveness of the approved qualified project in relation to other development efforts aimed at supplying the same market;

(2) the terms should accommodate the interests of the state, affected municipalities, and the project sponsors under a wide range of economic conditions, potential project structures, and marketing arrangements;

(3) the state's and affected municipalities' combined share of the economic rent of the approved qualified project under the contract should be relatively progressive; that is, the state's and affected municipalities' combined annual share of the economic rent of the approved qualified project generally should not increase when there are decreases in project profitability, or decrease when there are increases in project profitability;

(4) the state's and affected municipalities' combined share of the economic rent of the approved qualified project under the contract should be relatively lower in the earlier years than in the later years of the approved qualified project;

(5) the terms should allow the project sponsors to retain a share of the economic rent of the approved qualified project that is sufficient to compensate the sponsors for risks under a range of economic circumstances;

(6) the terms should provide the state and affected municipalities with a significant share of the economic rent of the approved qualified project, when discounted to present value, under favorable price and cost conditions;

(7) the method for calculating the periodic payment in lieu of certain taxes under the contract should be clear and unambiguous; and

(8) while cost calculations for the approved qualified project under the contract should be based on amounts that closely approximate actual costs, agreed-upon formulas reflecting reasonable economic assumptions should be used if possible to promote administrative certainty and efficiency.

(c) Except as provided in (b) of this section, the commissioner's discretion under this section in developing proposed terms for a contract under AS 43.82.020 is not limited to consideration of the economic rent of the approved qualified project.

Sec. 43.82.220. Contract terms relating to royalty.

(a) Notwithstanding any contrary provisions of AS 38, the commissioner of natural resources, with the concurrence of the commissioner of revenue and the affected parties holding a state lease or unit agreement, may develop proposed terms for inclusion in a contract under AS 43.82.020 that modify the timing and notice provisions of the applicable oil and gas leases and unit agreements pertaining to the state's rights to receive its royalty on gas in kind or in value if

(1) the viability of the approved qualified project depends on long-term gas purchase and sale agreements;

(2) certainty over time regarding the quantity of royalty gas that the state may be taking in kind is needed to secure the long-term purchase and sale agreements;

(3) the specified period of the state's commitment to take its royalty share in value or in kind does not exceed the term of the purchase and sale agreements; and

(4) the modification does not impair the ability of the approved qualified project or the state to meet the reasonably foreseeable demand in this state for gas within economic proximity of the project during the term of the contract developed under AS 43.82.020 .

(b) Notwithstanding any contrary provisions of AS 38, the commissioner of natural resources, with the concurrence of the commissioner of revenue and the affected parties holding a state lease or unit agreement, may develop proposed terms for inclusion in a contract under AS 43.82.020 that establish a valuation method for the state's royalty share of the gas production from an approved qualified project.

(c) The commissioner of revenue shall include any proposed terms relating to royalty developed in accordance with this section in the proposed contract under AS 43.82.400 .

(d) Nothing in this chapter permits modification of the state's rights that relate to timing, notice, and rights to receive oil royalty in kind or in value under oil and gas leases or unit agreements.

Sec. 43.82.230. Contract terms relating to hiring of Alaska residents and contracting with Alaska businesses.

(a) The commissioner shall include in a contract under AS 43.82.020 a term requiring the qualified sponsor or qualified sponsor group and contractors of the qualified sponsor or qualified sponsor group to comply with all valid federal, state, and municipal laws relating to hiring Alaska residents and contracting with Alaska businesses to work in the state on the approved qualified project and not to discriminate against Alaska residents or Alaska businesses. Within the constraints of law, the commissioner shall also include in a contract under AS 43.82.020 a term that requires the qualified sponsor or qualified sponsor group and contractors of the qualified sponsor or qualified sponsor group to employ Alaska residents and to contract with Alaska businesses to work in the state on the approved qualified project to the extent the residents and businesses are available, competitively priced, and qualified.

(b) The commissioner shall include in a contract under AS 43.82.020 a term requiring the qualified sponsor or qualified sponsor group and contractors of the qualified sponsor or qualified sponsor group to

(1) advertise for available positions in newspapers in the location where the work is to be performed and in other publications distributed throughout the state, including in rural areas; and

(2) use Alaska job service organizations located throughout the state and not just in the location where the work is to be performed in order to notify Alaskans of work opportunities on the approved qualified project.

(c) Subject to the voluntary agreement of the qualified sponsor, the commissioner may include a term in the contract providing for incentives to encourage training and hiring of Alaska residents.

(d) This section does not create or abridge individual rights and does not create a private right of action for any person.

(e) For purposes of this section,

(1) "Alaska business" means a firm or contractor that

(A) has held an Alaska business license for the preceding 12 months;

(B) maintains, and has maintained for the preceding 12 months, a place of business in the state that competently and professionally deals in supplies, services, or construction of the nature required for the approved qualified project; and

(C) is

(i) a sole proprietorship and the proprietor is an Alaska resident;

(ii) a partnership and more than 50 percent of the partnership interest is held by Alaska residents;

(iii) a limited liability company and more than 50 percent of the membership interest is held by Alaska residents;

(iv) a corporation that has been incorporated in the state or is authorized to do business in the state; or

(v) a joint venture and a majority of the venturers qualify as Alaska businesses under this paragraph;

(2) "Alaska job service organizations" means those offices maintained by the state and recommended by the Department of Labor and Workforce Development whose functions are to aid the unemployed or underemployed in finding employment;

(3) "Alaska resident" means a natural person who

(A) receives a permanent fund dividend under AS 43.23; or

(B) is registered to vote under AS 15 and qualifies for a resident fishing, hunting, or trapping license under AS 16;

(4) "available," as applied to an Alaska resident or Alaska business, means that the resident or business is available for employment at the time required and is located anywhere in the state, not just in the area of the state where the work is to be performed;

(5) "qualified," as applied to an Alaska resident or Alaska business, means that the resident or business possesses the requisite education, training, skills, certification, or experience to perform the work necessary for a particular position or to perform a particular service.

Sec. 43.82.240. Use of an independent contractor.

(a) The commissioner may use independent contractors to assist in the evaluation of an application or in the development of contract terms under AS 43.82.200 . The commissioner may condition the development of a contract under AS 43.82.020 on an agreement by the applicant to reimburse the state for the reasonable expenses of independent contractors under this section. A reimbursement of expenses that is required in an agreement authorized by this subsection may not exceed $1,500,000 for each application.

(b) An independent contractor selected under this section must sign an agreement regarding confidentiality and disclosures consistent with the determinations made under AS 43.82.310 before the contractor may review information that is determined confidential under AS 43.82.310 .

(c) Selection of an independent contractor under this section is not subject to AS 36.30 (State Procurement Code).

Sec. 43.82.250. Term of contract; effective date.

The term of a contract developed under AS 43.82.020 may be for no longer than is necessary to develop the stranded gas that is subject to the contract; however, the term of the contract may not exceed 35 years from the commencement of commercial operations of the approved qualified project.

Sec. 43.82.260. Change of parties to an application or a contract; as gnment of interests.

(a) A qualified sponsor or member of a qualified sponsor group may assign an interest in or add or withdraw a party to an application under AS 43.82.120 only if the commissioner has

(1) made a finding that the assignment, addition, or withdrawal is consistent with the requirements of AS 43.82.110 ; and

(2) given prior written approval for the assignment, addition, or withdrawal.

(b) A contract developed under this chapter may provide for the assignment to or withdrawal of a qualified sponsor or member of a qualified sponsor group.

(c) Upon being added to an application under this section, a party becomes a qualified sponsor or a member of a qualified sponsor group, as appropriate, for the relevant project.

(d) The commissioner may not unreasonably withhold approval under (a) of this section, but may condition the approval in any way reasonably necessary to protect the fiscal interests of the state and to further the purposes of this chapter.

(e) For purposes of this section, an assignment includes a transfer of stock or a partnership interest in a manner that changes control of a qualified sponsor or member of a qualified sponsor group.

Sec. 43.82.270. Project plans and work commitments.

A contract under AS 43.82.020 must include the qualified project plan approved under AS 43.82.140 and provisions for updating the plan at reasonable intervals until the commencement of commercial operations of the approved qualified project. The commissioner of revenue, in consultation with the commissioner of natural resources, may, as a term in a contract under AS 43.82.020 , include work commitments or other obligations in the contract to be accomplished before the commencement of commercial operations of the approved qualified project.

Article 04. REQUESTS FOR INFORMATION; CONFIDENTIALITY; DISCLOSURE OF INFORMATION

Sec. 43.82.300. Requests for information.

The commissioner of revenue or the commissioner of natural resources may request from an applicant information that the respective commissioner determines is necessary to perform the respective commissioner's responsibilities under AS 43.82.140 . If the application is approved under AS 43.82.140 , the respective commissioner shall require the successful applicant to provide financial, technical, and market information regarding the qualified project that the respective commissioner determines is necessary for the purpose of developing contract terms for the qualified project under AS 43.82.200 . If requested information is not provided, the commissioner of revenue may not continue to review the application under AS 43.82.140 or develop the contract under AS 43.82.200 - 43.82.270, as applicable.

Sec. 43.82.310. Disclosure of information; confidentiality.

(a) An applicant may request confidential treatment of information that the applicant provides under AS 43.82.300 by clearly identifying the information and the reasons supporting the request for confidential treatment. The commissioner of revenue or the commissioner of natural resources, as appropriate, shall keep the information confidential until the commissioner determines whether the requirements of (b) of this section are met. If the commissioner of revenue or the commissioner of natural resources has not made a determination under (b) of this section within 14 days after receiving a request for confidential treatment, the request is considered denied. If the appropriate commissioner determines that the information does not meet the requirements of (b) of this section or if the commissioner fails to make a determination within 14 days, the commissioner shall return the information and any copies of it at the request of the applicant. If the commissioner of revenue or the commissioner of natural resources, as appropriate, returns information under this subsection, the commissioner shall cease review of the application or cease contract development under AS 43.82.200 - 43.82.270, as appropriate, unless the commissioner determines that the returned information is unnecessary to make a determination on the application or to develop contract terms under AS 43.82.200 - 43.82.270.

(b) If requested by the applicant, information provided to the commissioner of revenue or the commissioner of natural resources under AS 43.82.300 shall be kept confidential if the commissioner receiving the information determines, upon an adequate showing by the applicant, that the information

(1) is a trade secret or other proprietary research, development, or commercial information that the applicant treats as confidential;

(2) affects the applicant's competitive position; and

(3) has commercial value that may be significantly diminished by public disclosure or that public disclosure is not in the long-term fiscal interests of the state.

(c) Information determined to be confidential under (b) of this section is confidential under that subsection only so long as is necessary to protect the competitive position of the applicant, to prevent the significant diminution of the commercial value of the information, or to protect the long-term fiscal interests of the state. The commissioner of revenue or the commissioner of natural resources, as appropriate, may not release information that the commissioner has previously determined to be confidential under (b) of this section without providing the applicant notice and an opportunity to be heard.

(d) Notwithstanding the limitation in (c) of this section, the Department of Revenue and the Department of Natural Resources may provide to one another, to the Department of Law, to the legislature, and to the Office of the Governor any information provided under AS 43.82.300 relevant to the implementation of this chapter or to the enforcement of state or federal laws. Information that is exchanged under this subsection that was determined to be confidential under (b) of this section remains confidential except as provided in (c) of this section. The portions of the records and files of the Department of Revenue, the Department of Natural Resources, the Department of Law, the legislature, and the Office of the Governor that reflect, incorporate, or analyze information that is determined to be confidential under (b) of this section are not public records except as provided in (c) of this section.

(e) Notwithstanding the limitation in (c) of this section, information that is determined to be confidential under (b) of this section shall be disclosed on request by the commissioner of revenue, the commissioner of natural resources, or the attorney general to a legislator; to the legislative auditor; and, as directed by the chair or vice-chair of the Legislative Budget and

Audit Committee, to the director of legislative finance, to the permanent employees of those divisions who are responsible for evaluating a contract under AS 43.82.020, and to agents or contractors of the legislative auditor or the director of legislative finance who are engaged to evaluate a contract under AS 43.82.020 . Information that is determined to be confidential under (b) of this section may also be disclosed by the commissioner of revenue or the commissioner of natural resources to an independent contractor under AS 43.82.240 or to a municipal advisory group established under AS 43.82.510 . Before confidential information is disclosed under this subsection, the person receiving the information must sign an appropriate confidentiality agreement.

(f) If the commissioner of revenue chooses to develop a contract under AS 43.82.020 , the portions of the records and files of the Department of Revenue, the Department of Natural Resources, the Department of Law, and a municipal advisory group established under AS 43.82.510 that reflect, incorporate, or analyze information that is relevant to the development of the position or strategy of the commissioner of revenue, the commissioner of natural resources, or the attorney general with respect to a particular provision that may be incorporated into the contract are not public records until the commissioner of revenue gives public notice under AS 43.82.410 of the commissioner's preliminary findings and determination under AS 43.82.400 . Nothing in this subsection

(1) makes a record or file of the Department of Revenue, the Department of Natural Resources, or the Department of Law a public record that otherwise would not be a public record under AS 40.25.100 - 40.25.220;

(2) affects the confidentiality provisions of (a) - (e) of this section; or

(3) abridges a privilege recognized under the laws of this state, whether at common law or by statute or by court rule.

Article 05. CONTRACT REVIEW, APPROVAL, AND TERMINATION

Sec. 43.82.400. Preliminary findings and determination regarding the contract.

(a) If the commissioner develops a proposed contract under AS 43.82.200 - 43.82.270, the commissioner shall

(1) make preliminary findings and a determination that the proposed contract terms are in the long-term fiscal interests of the state and further the purposes of this chapter; and

(2) prepare a proposed contract that includes those terms and shall submit the contract to the governor.

(b) To make the preliminary findings and determination required by (a)(1) of this section, the commissioner shall compare the projected public revenue anticipated from the approved qualified project with the estimated operating and capital costs of the additional state and municipal services anticipated to arise from the construction and operation of the approved qualified project. The commissioner shall address the reasonably foreseeable effects of the proposed contract on the public revenue.

(c) In conjunction with the making of preliminary findings and determination required by (a)(1) of this section, the commissioner shall describe the principal factors, including the projected price of gas, projected production rate or volume of gas, and projected recovery, development, construction, and operating costs, upon which the determination made under (a)(1) of this section is based. If the commissioner has previously submitted a proposed contract to the governor, the commissioner shall describe any material differences between the terms of the currently proposed contract and the previously proposed contract.

Sec. 43.82.410. Notice and comment regarding the contract.

The commissioner shall

(1) give reasonable public notice of the preliminary findings and determination made under AS 43.82.400 ;

(2) make copies of the proposed contract, the commissioner's preliminary findings and determination, and, to the extent the information is not required to be kept confidential under AS 43.82.310 , the supporting financial, technical, and market data, including the work papers, analyses, and recommendations of any independent contractors used under AS 43.82.240 available to the public and to

(A) the presiding officer of each house of the legislature;

(B) the chairs of the finance and resources committees of the legislature; and

(C) the chairs of the special committees on oil and gas, if any, of the legislature;

(3) offer to appear before the Legislative Budget and Audit Committee to provide the committee a review of the commissioner's preliminary findings and determination, the proposed contract, and the supporting financial, technical, and market data; if the Legislative Budget and Audit Committee accepts the commissioner's offer, the committee shall give notice of the committee's meeting to the public and all members of the legislature; if the financial, technical, and market data that is to be provided must be kept confidential under AS 43.82.310 , the commissioner may not release the confidential information during a public portion of a committee meeting; and

(4) establish a period of at least 30 days for the public and members of the legislature to comment on the proposed contract and the preliminary findings and determination made under AS 43.82.400 .

Sec. 43.82.420. Coordination of public and legislative review.

To the extent practicable, the commissioner shall coordinate the public comment opportunity provided under AS 43.82.410 (4) with a review by the Legislative Budget and Audit Committee under AS 43.82 410 (3).

Sec. 43.82.430. Final findings, determination, and proposed amendments; execution of the contract.

(a) Within 30 days after the close of the public comment period under AS 43.82.410 (4), the commissioner of revenue shall

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

(2) after consultation with the commissioner of natural resources, if appropriate, and with the pertinent municipal advisory group established under AS 43.82.510 , prepare a list of proposed amendments, if any, to the proposed contract that the commissioner of revenue determines are necessary to respond to public comments;

(3) make final findings and a determination as to whether the proposed contract and any proposed amendments prepared under (2) of this subsection meet the requirements and purposes of this chapter.

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

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

Sec. 43.82.435. Legislative authorization.

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

Sec. 43.82.440. Judicial review.

A person may not bring an action challenging the constitutionality of a law authorizing a contract enacted under AS 43.82.435 or the enforceability of a contract executed under a law authorizing a contract enacted under AS 43.82.435 unless the action is commenced within 120 days after the date that the contract was executed by the state and the other parties to the contract.

Sec. 43.82.445. Administrative termination of a contract.

(a) The commissioner shall include terms in a contract developed under AS 43.82.020 that provide for administrative termination of a party's rights under the procedures and conditions set out in this section if the party has

(1) ceased to meet the requirements of AS 43.82.110 as a qualified sponsor or qualified sponsor group;

(2) intentionally or fraudulently misrepresented, in whole or in part, material facts or circumstances upon which the contract was made;

(3) failed to comply with a condition or material term of the contract or a provision of this chapter; or

(4) failed to comply with the approved qualified project plan or any updated project plan.

(b) Before administrative termination of a contract under this section, the commissioner shall give notice to the parties of the commissioner's intent to terminate the contract and an opportunity to be heard. The commissioner may also provide the parties an opportunity to cure any deficiency that is the basis for the termination if the commissioner determines that curing the deficiency is appropriate under the circumstances.

(c) Notwithstanding (a) and (b) of this section, the commissioner may not administratively terminate a contract after the party has committed full project funding except as provided in (e) of this section.

(d) A party to a contract who is affected by the commissioner's action to terminate under (a) of this section may file an appeal with the superior court under the Alaska Rules of Appellate Procedure.

(e) The commissioner may provide terms and conditions in a contract developed under AS 43.82.020 upon which a party's rights under the contract may be administratively terminated after the party commits full project funding.

Article 06. MUNICIPAL PARTICIPATION

Sec. 43.82.500. Obligation to share payments with municipalities.

If the commissioner develops a contract under AS 43.82.020 that includes terms that exempt a party to the contract, and the property, gas, products, and activities associated with the approved qualified project that is subject to the contract, from a municipal tax or assessment in accordance with AS 29.45.810 or AS 29.46.010 (b), or AS 43.82.200 and 43.82.210, the commissioner shall include a term in the contract that the party pay a portion of the periodic payments due under the contract to the revenue-affected municipality.

Sec. 43.82.505. Payments to economically affected municipalities.

If the commissioner executes a contract under AS 43.82.020 that will produce one or more economically affected municipalities, the commissioner shall include a term in the contract that provides for a portion of the periodic payments to the economically affected municipalities under the principles in AS 43.82.520 .

Sec. 43.82.510. Municipal advisory group.

(a) If the commissioner approves an application and proposed project plan under AS 43.82.140 and decides to develop a contract under AS 43.82.020 and 43.82.200, the commissioner shall notify each revenue-affected municipality and economically affected municipality.

(b) The mayor of a municipality notified by the commissioner under (a) of this section may appoint one representative to a municipal advisory group in relation to the application.

(c) Each municipal advisory group serves until a final action is taken on the application for which the group was appointed.

(d) Each municipal advisory group shall elect a chair.

Sec. 43.82.520. Duties of the commissioner of revenue in relation to municipal participation.

(a) The commissioner shall meet with each municipal advisory group periodically to report on the development of the contract provisions that affect the municipalities.

(b) In developing a contract under AS 43.82.200 - 43.82.270, the commissioner shall ensure that each revenue-affected municipality and economically affected municipality receives a fair and reasonable share of the payments provided under AS 43.82.210 in accordance with the following principles:

(1) the share of the payments to revenue-affected municipalities should be given priority over payments to economically affected municipalities with due regard to the anticipated size of the tax base that the contract would exempt from municipal taxation by revenue-affected municipalities;

(2) the share of the payments to municipalities should be determined with due regard to the anticipated economic and social burdens that would be imposed on the municipality by construction and operation of the project;

(3) the respective shares of the total payments to the state and to municipalities should be fixed in a manner to ensure that their respective interests are aligned;

(4) to the extent practicable, the periodic amounts paid to each of the municipalities should be stable and predictable; and

(5) to the extent practicable, the provisions for sharing payments with municipalities should be consistent with the principles established in AS 43.82.210 (b).

(c) In establishing the municipal shares under (b) of this section, the commissioner shall consult with the pertinent municipal advisory group.

Sec. 43.82.600. Governing law.

If a provision of this chapter conflicts with another provision of state or municipal law, the provision of this chapter governs.

Sec. 43.82.610. Regulations.

The commissioner of revenue, the commissioner of natural resources, and the commissioner of labor and workforce development may adopt regulations to carry out their respective duties under this chapter.

Sec. 43.82.620. Procedures for collection of amounts due; security.

(a) The commissioner may adopt procedures for the collection of amounts due the state under a contract developed under AS 43.82.020 , including the collection of interest and penalties.

(b) The commissioner may require a party to a contract developed under AS 43.82.020 to provide security sufficient to guarantee amounts due under the contract.

Sec. 43.82.630. Reports and audits.

The commissioner may require periodic reports from and may at reasonable intervals conduct audits and inspect the books of a party that has entered into a contract developed under AS 43.82.020 to ensure compliance with the provisions of this chapter and the regulations adopted under this chapter and of the terms of the contract.

Sec. 43.82.640. Annual report of the commissioner of labor and workforce development.

On an annual basis, the commissioner of labor and workforce development shall prepare and present to the legislature a comprehensive report on each party to a contract with the state developed under AS 43.82.020 , and its contractors, regarding the state residency of the employees working in this state on the approved qualified project that is subject to the contract. The commissioner of labor and workforce development shall use state data bases, including data from the quarterly reports by a party to the contract developed under AS 43.82.020 and its contractors for unemployment insurance purposes, to determine state residency of employees regarding compliance with AS 43.82.230 .

Article 08. GENERAL PROVISIONS

Sec. 43.82.900. Definitions.

In this chapter, unless the context requires otherwise,

(1) "affected municipality" means an economically affected municipality or a revenue-affected municipality;

(2) "commencement of commercial operations" means the start of regular deliveries of marketable products from an approved qualified project;

(3) "cubic foot of gas" means the quantity of gas contained in a volume of one cubic foot at a standard temperature of 60 degrees Fahrenheit and a standard absolute pressure of 14.65 pounds per square inch;

(4) "economically affected municipality" means a municipality the commissioner of revenue determines will be reasonably required to provide additional public services under the terms proposed in an application approved under AS 43.82.140 (a); the commissioner may consider historical data from construction of the Trans Alaska Pipeline System, and information submitted by a municipality in making the determination;

(5) "economic proximity" means the distance within which a person may be willing to design, construct, and operate a gas line to provide service to a local consumer;

(6) "economic rent" means the estimated total gross revenue less estimated total costs for a qualified project over the term of a contract under AS 43.82.020 , measured in undiscounted nominal dollars; for purposes of this paragraph, total costs do not include a rate of return on capital, financing costs, or any payments to governments;

(7) "full project funding" means full approval by a party to a contract under AS 43.82.020 for the expenditure of the capital necessary for construction and operation of the approved qualified project that is subject to the contract;

(8) "gas" has the meaning given in AS 43.55.900 ;

(9) "group" means two or more persons;

(10) "lease or property" has the meaning given in AS 43.55.900 ;

(11) "periodic payment" means payment made in lieu of one or more other taxes under a contract under AS 43.82.020 ;

(12) "revenue-affected municipality" means a municipality that the commissioner of revenue reliably expects will be restricted from imposing a tax, or a portion of a tax, as a result of implementation of a contract developed under this chapter;

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

Sec. 43.82.990. Short title.

This chapter may be cited as the Alaska ►►Stranded◄◄ ►►Gas◄◄ ►►Development◄◄ ►►Act◄◄.

Validity of Application and Project Plan

The submittal of an application and proposed project plan by a sponsor or sponsor group is the initial step toward the fiscal contract development process. Based on the information available in the application and project plan, the state determines if a project, sponsor or sponsor group, and project plan are qualified under the criteria in the SGDA.

The producers group submitted an application, including a proposed project plan, for development of a fiscal contract under the SGDA on January 20, 2004. The statement of qualifications of the project and sponsor group and the proposed project plan, as described in the "Amended Application for Development of a Contract under AS 43.82, the Alaska Stranded Gas Development Act," are summarized below.

Qualified Project

Under AS 43.82.100, three criteria must be met in order for the state to determine that a project is qualified under the SGDA. The three criteria are: commercialization, production threshold, and in-state demand, and are summarized below.

Commercialization

Under subsection AS 43.82.100(1), a project is qualified if it principally involves (A) the transportation of natural gas by pipeline to one or more markets, together with any associated processing or treatment; (B) the export of liquefied natural gas from the state to one or more other states or countries; or (C) any other technology that commercializes the shipment of natural gas within the state or from the state to one or more other states or countries.

The project described in the producers group's application involves the transportation of natural gas by pipeline to one or more markets, together with any associated processing or treatment; therefore, the project meets this criterion. The project consists of four major components—a GTP, a pipeline from Alaska to Alberta, a potential NGL plant, and a potential pipeline from Alberta to Chicago.

The GTP would be located on the North Slope and would be designed to remove impurities from the natural gas stream to meet inlet pipeline specifications. These pipeline specifications would also require that the gas be compressed and chilled. The pipeline design consists of 52-inch buried pipe operating at approximately 2,500 pounds per square inch (psi). Compressor stations would be placed at regular intervals.

An NGL Plant is expected to be included in the project to allow export and subsequent recovery of hydrocarbon products that are currently too light to blend with crude oil for delivery through the TAPS. This NGL removal would likely be required in order to condition the natural gas to meet downstream market specifications. An NGL Plant may be a newly constructed facility or an existing facility. A new-build plant could theoretically be located anywhere along the pipeline route.

The final portion of the project involves the export of gas from Alberta. Export alternatives from Alberta include utilizing existing pipeline capacity made available by anticipated declines in existing Canadian gas production, expansion of existing pipeline systems, or installation of other new-build pipeline concepts.

Production Threshold

AS 43.82.100(2) establishes a production threshold of at least 500,000,000,000 (500 billion) cubic feet of gas within 20 years from the commencement of commercial operat'r is

The project described in the producers group's application would produce significantly more than 500 bcf within 20 years from the commencement of commercial operations; therefore, the project meets this criterion. The producers group has developed a preliminary plan to build a natural gas pipeline and related facilities which would have a design capacity to transport approximately 4 bcf/d of stranded gas to markets in Canada and the Lower 48 States. If this capacity were achieved, the project would produce over 500 billion cubic feet of stranded gas within the first year of commercial operations, even with the expected volume ramp up during the first months after gas begins to flow.

In-state Demand

Under AS 43.82.100(3) a qualified project must be capable, subject to applicable commercial regulation and technical and economic considerations, of making gas available to meet the reasonably foreseeable demand in this state for gas within the economic proximity of the project

The project described in the producers group's application is capable of making gas available to meet the foreseeable demand for gas in Alaska, within the economic proximity of the project; therefore, the project meets this criterion. The producers group recognizes the strong interest in making gas available for in-state use. The producers group plans to work cooperatively with potential downstream investors and the state in a way that is consistent with the well-established regulatory framework of fair and open access. Consistent with this regulatory framework, gas can be made available for in-state use under reasonable terms and conditions. The producers group's proposed project plan describes the principles under which natural gas may be made available. The four principles are listed in Section 3.3.3.

Qualified Sponsor or Sponsor Group

Two criteria must be met in order for the state to determine that a sponsor or sponsor group is qualified under the SGDA. The two criteria are described in the following subsection headings.

Commitment

Under 43.82.110(1) a person or group can be deemed qualified if they intend to own an equity interest in a qualified project, intend to commit gas that is owned to a qualified project, or hold the permits that the department determines are essential to construct and operate a qualified project

The producers group will own an equity interest in the project; therefore, the producers group meets this criterion. In addition, the members of the producers group expect as individual companies, either directly, through affiliates, or through affiliated interests in subsequently created legal entities, to commit their gas to the project.

Resources

AS 43.82.110(2) states that a person or group can be qualified if they meet one or more of the following criteria: 1) Owns at least 10 percent of the gas proposed to be developed; 2) Has a right to purchase at least 10 percent of the gas proposed to be developed; 3) Has a right to acquire, control, or market at least 10 percent of the gas proposed to be developed; 4) Has a net worth of at least 10 percent of the estimated cost of constructing the project; and/or 5) Has an unused line of credit equal to at least 15 percent of the estimated cost of constructing the project.

The producers group owns at least 10 percent of the gas proposed to be developed; therefore, the sponsor group meets this criterion. The producers group, as owners in both the Prudhoe Bay and Point Thomson gas resources, holds a working interest in approximately 32 tcf of North Slope stranded gas; taking out the state's royalty share, this amount represents a net share of approximately 29 tcf. Several assumptions must be made about the project to determine the producers group's share of the total volume of gas to be delivered by the project. Assuming sufficient natural gas supplies are developed to fill a 4 bcf/d design capacity for 35 years, approximately 50 tcf of stranded gas would be delivered to the market by the pipeline project. As such, the producers group would have interest in over 60 percent of the total stranded gas assumed to be produced, well in excess of the 10 percent gas resource access requirement for qualified sponsors.

Either directly or through affiliates, the members of the producers group are also owners in other North Slope fields containing additional natural gas resources, including the Alpine, Endicott, Milne Point, and Northstar fields, as well as other undeveloped leases. Furthermore, the producers group has the potential to secure new leases and successfully discover and develop additional gas resources

Qualified Project Plan

Under AS 43.82.130, three criteria must be met in order for the state to determine that the proposed project plan is qualified under the SGDA. The three criteria are described in the following subsection headings.

Diligent Development

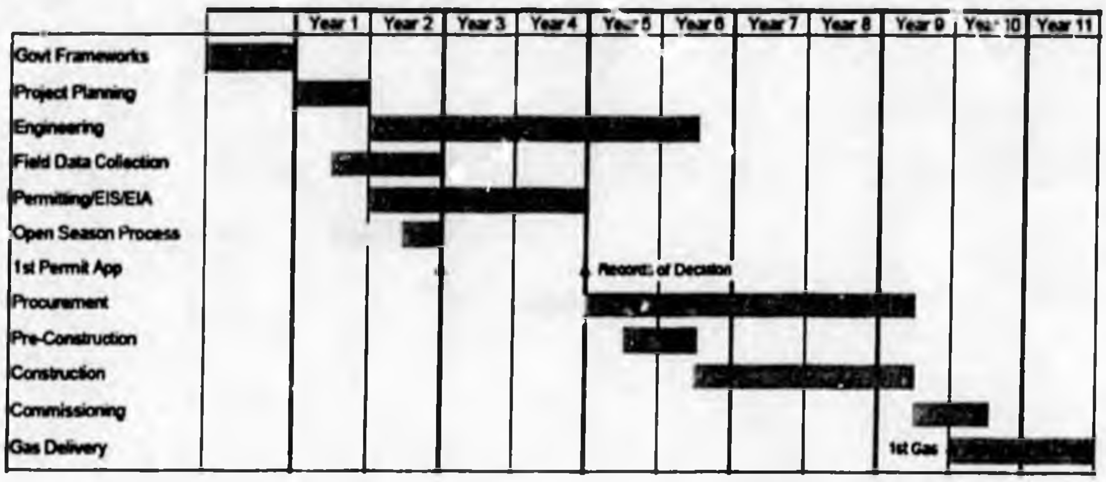
The proposed project plan submitted with the producers group's application reflects a proposal for diligent development of the project on the part of the applicant as required by AS 43.82.130(1); therefore, the proposed project plan meets this criterion. The work accomplished by the producers group prior to submitting an application under the SGDA includes a $125 million study conducted in 2001 and 2002 to assess the feasibility of constructing a pipeline to deliver Alaska gas to Canadian and Lower 48 markets. The study assessed the cost, technology, regulatory, and environmental issues associated with the project. The major system components considered include a GTP, an Alaska to Alberta pipeline system, a potential NGL Plant, and a potential Alberta to Lower 48 pipeline system.

Following the conclusion of the 2001-02 joint study, the primary focus of activity for the producers group shifted to addressing key areas of risk identified in the study. Specific joint activities to develop the necessary government frameworks have included pursuit of U.S. Federal enabling legislation, and support of the reauthorization of the SGDA in Alaska. Further joint technical work also continued, including the evaluation of various cost reduction ideas such as field trials of high efficiency trenching machines and evaluation of potential transportation infrastructure improvements.

The figure reproduced below presents a conceptual timeline for planning and constructing the natural gas pipeline and related facilities. Following the establishment of suitable government frameworks (such as this SGDA process), the overall timeline spans ten years, beginning with project planning, and ending with mechanical completion and commissioning. The schedule assumes that project funding, which triggers the initiation of major equipment procurement and module fabrication, would be contingent on receiving key government approvals (i.e., Records of Decision). The current project timeline assumes that each milestone will be successfully completed. However, if issues do arise, the schedule would be extended accordingly.

Figure 1. Conceptual Project Timeline

Figure 5.3(1) Conceptual Project Timeline



Source: "Amended Application for Development of a Contract under AS 43.82, the Alaska Stranded Gas Development Act" prepared by British Petroleum (Alaska), Inc., ConocoPhillips Alaska, Inc., and ExxonMobil Alaska Production, Inc.

Conflict with Obligations to State

The proposed project plan submitted with the producers group's application does not materially conflict with the obligations of a lessee to the state under a lease or under a pool, unit, or other agreement with the state as noted under AS 43.82.130(2); therefore, the proposed project plan meets this criterion. While the proposed project plan anticipates a fiscal contract that provides "fiscal simplicity and clarity" for the producers group's gas and leases, it does not by itself contain any express proposals that conflict with the producers group's current lease or unit obligations. Nothing in the plan conflicts with the producers group's representation that "unless and until provided otherwise in a contract under this application, all existing obligations shall continue to be governed by existing leases and unit agreements with the State."

3.3.3 In-state Demand

The proposed project plan submitted with the producers group's application describes satisfactory methods and terms for accommodating reasonably foreseeable demand for gas in the state as required under AS 43.82.130(3); therefore, the proposed project plan meets this criterion. The producers group plans to work cooperatively with potential downstream investors (e.g., local distribution companies, industrial users, marketers, and utilities) and the state in a way that is consistent with the well-established regulatory framework of fair and open access. This should put these prospective customers and the state in a position to satisfy reasonably foreseeable local gas demand within economic proximity of the pipeline project during the term of the contract. The producers group lists the following principles under which natural gas may be made available.

- The producers group would work with potential downstream investors and the state to identify pipeline connection locations along the pipeline that correspond with reasonably foreseeable in-state demand that is within economic proximity of the pipeline.
- Potential downstream investors would have an opportunity to negotiate gas purchase contracts with any party holding title to gas, (i.e., individual producer, marketer or local distribution company, or the State of Alaska).
- Potential downstream investors meeting objective creditworthiness standards would have the opportunity to contract for pipeline capacity on the Alaska Gas Pipeline Project. The allocation of capacity on interstate pipelines is governed by the regulations and policies of the FERC. The initial open season process provides a potential shipper with the ability to secure capacity via a long-term contract for natural gas shipment to its local gas conditioning and distribution infrastructure and ultimate sale to end-users. A similar open season process would be used to identify potential shippers and allocate capacity for any subsequent pipeline expansions. In addition, potential shippers would have the opportunity, subject to FERC regulations, to contract for unused capacity that shippers may release into the secondary market.
- The producers group has no current plans or intent to build or own local gas conditioning and distribution infrastructure (e.g., pressure reduction equipment, calorific control equipment, spur lines, local gas distribution systems, etc.) that may be required to serve in-state demand. Subsequent downstream gas conditioning and distribution infrastructure would be the responsibility of downstream investors.

Letter of Approval

On January 23, 2004, the Commissioner: (a) determined that the proposed project is a qualified project under the SGDA; (b) determined that BP, CP and EM are qualified sponsors under the SGDA; and (c) with the concurrence of the commissioner of ADNR, approved the application and the proposed project plan.

In the letter of approval the Commissioner observes that the producers group's application identifies two of the possible routes to bring Alaska North Slope stranded gas resources to market. One route would generally follow the TAPS route and then the Alaska Canadian highway through Canada and into Alberta (the Highway Route). The second pipeline route would cross state land in or adjacent to the Beaufort Sea off the north coast of Alaska and then proceed east to the Mackenzie River valley and south to Alberta (the Over-the-Top Route). The Commissioner notes in the letter that the Over-the-Top Route is inconsistent with current state law.

The Commissioner also acknowledges that no final commercial decision has been made on any route and indicates that the state intends to fully discuss all aspects of the permitable, qualified project consistent with the application submission.

Is Alaska North Slope Gas Stranded?
Economic Analysis and Determination
Alaska Department of Revenue

I. Executive Summary

Natural gas on the Alaska North Slope (ANS) is considered legally "stranded" under AS 43.82 if it is not being marketed, and will not be marketed due to cost and/or price conditions. The vast preponderance of natural gas on the North Slope qualifies under such consideration. This includes both currently produced but recycled gas and gas in fields not yet producing. The economic reasons for stranding consist of high costs of transporting the gas to market [both capital and operating] relative to the uncertain future natural gas price, and the rate of return on the potential investment relative to other options. Additionally, the magnitude of any transportation infrastructure construction project itself is an economic factor that contributes to the conclusion. Eventually, gas producers or others may construct some means to transport North Slope gas to market. However, due to competition from other projects throughout the world which have higher economic returns, the Alaskan project may face years of delay without State fiscal incentives.

II. Introduction

Per the Alaska Stranded Gas Development Act (AS 43.82.900 (13), " 'stranded gas' means gas that is not being marketed due to prevailing costs or price conditions as determined by an economic analysis by the commissioner [of the State of Alaska Department of Revenue] for a particular project." This report constitutes that determination.

For this determination, prevailing value and costs are those for the period of the contract. The Stranded Act states the following in AS 43.82.900 (6): ' "economic rent" means the estimated total gross revenue less estimated total costs for qualified project ***over the term of a contract*** [emphasis added]...' Since the project would not begin for 10 years, and would last 30 or more years, prevailing value and costs are those that are forecast for the next 40 plus years.

Not only are prevailing values and costs important in making the determination, but the rate of return a company would receive under the prevailing values and costs becomes important. Since companies have a portfolio of projects available for investment, the relative rank of the Alaska project, in comparison to other projects in the company's portfolio becomes important in determining if Alaska's gas is stranded.

If gas is determined to be stranded, the State is authorized to establish fiscal terms [related to new investment in advance of project initiation] that would be tailored to the project's particular economic conditions. These terms may provide for payments in lieu of tax payments to offer greater chances of project success while maximizing the benefit to the people of the State.

At the time of enactment of AS 43.82, the Legislature found as a matter of fact that "a vast quantity of gas in Alaska is stranded from commercial development because of the cost associated with providing access to markets for that gas."(§ 3 ch 104 SLA 1998 at Section 1(1)). This analysis reviews events since 1998 in the History section to see if recent events alter this finding.

Three groups submitted projects under the Stranded Gas Development Act and they are the following: [1] the "Sponsor Group" proposal which is the proposal submitted by ConocoPhillips, BP, and ExxonMobil [2] the TC proposal submitted by TransCanada Company [TC] and [3] the AGPA proposal submitted by the Alaska Gas Line Port Authority [AGPA]. The Sponsor Group proposal consists of a pipeline and related facilities that would carry approximately 4 billion cubic feet per day (bcf/d) of natural gas from the Alaska North Slope (ANS) to Alberta and on to North America markets. The TC proposal differs from the Sponsor Group proposal primarily in the ownership of the pipeline. Therefore the Sponsor proposal is analyzed as a proxy for either. The AGPA proposal differs from the first two in that it proposes shipping about 4 bcf/d of liquefied natural gas [LNG] from Valdez. To undertake this requires the construction of a pipeline of approximately 800 miles in length from the North Slope to Valdez, the construction of liquefaction facilities in Valdez, the construction of tankers to transport the LNG, and the construction of re-gasification facilities on the Pacific Coast of North America to receive the LNG and convert it to gas.

This analysis examines the reasons the gas is not being marketed and the reasons that no projects are under construction to market it. The analysis also considers the temporal nature of current and projected market conditions. If it is concluded that ANS natural gas is not being marketed due to prevailing cost or market conditions, then the gas is stranded. The term "prevailing" is interpreted to mean the cost or market conditions during the majority of the period when the gas is expected to be marketed.

III. History

Before 1998, the prospects for commercializing North Slope gas were elusive, owing mainly to low market prices which could not justify the high costs of any project to bring the gas to market. One or more such projects have been under active consideration for more than a quarter century. Recently, however, a number of significant events have occurred that have elevated the prospects for a viable project:

- The increase in US natural gas prices. The continued increase in North America gas demand has pushed up against available supply with the result that natural gas prices began to rise starting in 2000.

- The alignment of interests in the oil rim and the gas cap between the working interest owners at Prudhoe Bay subsequent to BP's purchase of Arco, and subsequent divesting of Arco's interests to ConocoPhillips in 2000.

- The aging of the Prudhoe Bay reservoir is approaching a point where removing, rather than recycling gas from the reservoir, will not materially affect oil recovery by the time a gas project would begin.

- The gas handling facility at Prudhoe Bay has reached its capacity. Any expansion would have limited impact on increasing crude oil production.

- The creation of Federal legislation in 2004 that provides opportunities for loan guarantees and tax benefits for a North Slope gas pipeline project.

In 2001, the Sponsor Group undertook a $125 million North Slope gas pipeline feasibility study. The proposed project plan submitted by the Sponsor Group is the result of that study. The estimated capital cost to build a pipeline and deliver the gas to Chicago, the closest large volume nexus with domestic gas pipelines, is about $21 billion[1].

IV. The Energy Density of Gas

When hydrocarbons such as oil or natural gas are sold, what is really being sold is the energy equivalent content, or British Thermal Units (BTU's). On a volumetric basis, natural gas has much lower BTU density than oil. At standard temperature and pressure, a cubic foot of oil has 1,000,000 BTU's. A cubic foot of gas has only 1,000 BTU's, or 1/1000th as much. This has important implications for the cost of moving gas to market.[2]

A thousand cubic feet (mcf) of gas contains only about 1/6 the amount of BTU's as a barrel of oil. The Trans-Alaska (oil) Pipeline (TAPS) is about 48 inches in diameter and at full capacity can ship about 2 million barrels of oil a day (about 12×10^{12} BTU's). The proposed gas pipeline will be slightly larger, and ship about 4 bcf/d of natural gas (about 4.66×10^{12} BTU's per day). (The gas will be compressed in the pipeline to about 1/170th of its atmospheric volume.) Thus the gas pipeline will only carry about 1/3 the number of BTU's as the oil pipeline. Yet, again, it will be larger, and require extensive compression to place and move the gas within it. The result is that gas is much more expensive to ship than oil.[3] And, the longer the pipeline, the higher the cost to transport the natural gas. This is discussed in detail below.

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[1] The original cost estimate has been updated to 2005 price levels.

[2] A cubic foot of gas at standard temperature and pressure contains about 1,000 BTU's. Due to the specific mixture of products contained within the gas, as is the case with the ANS gas to be transported to market, the BTU content can be higher. The BTU content of ANS marketable gas is projected to increase over time as the average is expected to be about 1,080 BTU per cubic foot.

[3] Two general types of natural gas are produced by drilling, referred to as dry gas and natural gas liquids (NGL). When gas is removed from the ground, it often contains water and other condensates. The water is

V. Natural Gas Supplies and Market

Each type of fuel has specific advantages and disadvantages. These include costs, associated byproducts, infrastructure requirements, specific use characteristics, energy generation factors, and so forth. At least at the present time, a mix of fuels is necessary since there is not enough fuel available from any one source to satisfy all needs worldwide. Therefore, natural gas contributes a significant part of world and domestic fuel supply. Due to many of its characteristics, natural gas is forecast to contribute an even greater percentage of fuel supplies for the foreseeable future[4].

There are 6,000 - 7,000 trillion cubic feet (tcf) of proven natural gas reserves in the world.[5] There are about 40 tcf of natural gas discovered in Alaska of which about 32 tcf are recoverable, most of it on the North Slope.[6 7] This equates to world reserves the size of about 200 North Slope reserves. Much of this gas worldwide is located at great distances from market. As a result, distance to market and geography have kept much of these reserves out of the market.

While these are proven reserves, there is tremendous potential worldwide for additional natural gas discoveries. In Alaska alone, there is an estimated gas resource potential of more than 200 tcf. This potential resource, regardless of size, is functionally not recoverable until there is a means of transporting it to market.

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separated and reinjected. Natural gas liquids, including ethane, propane, butane and lease condensate, are removed from the mixture and liquefied in a gas processing plant. On the North Slope, a portion of these NGLs are then injected into the TAPS line as part of the oil mixture, with the balance re-injected into the oil fields. Dry gas is composed primarily of methane and is not injectable into the TAPS line. This is the natural gas that is the focus of this analysis.

The weight of a barrel of oil is directly related to its American Petroleum Institute (API) gravity and specific gravity. The heavier the oil, the lower (smaller) its API gravity and the higher its specific gravity. Higher specific gravity relates to a denser substance so oil with a lower API gravity weighs more.

The BTU content of oil also is directly related to its API gravity. The higher the API gravity the more BTU's per weight of oil, however, as weight and BTU content are combined, lower API gravity oil has a higher BTU content per barrel. For example, at standard temperature and pressure, oil of 35° API gravity contains 5.965 million BTU per barrel while oil of 27° API gravity contains 6.096 million BTU per barrel. Since blended oil transported to Valdez has an API gravity within this range, 6 million BTU per barrel is a reasonable approximation.

[4] International Energy Agency, World Energy Outlook 2005. OECD, 2005, page 81.

[5] National Energy Information Center, U.S. Department of Energy at: www.eia.doe.gov/emeu/international/reserves.xls.

[6] Mineral Management Service, 2001 "Prospects For Development of Alaska Natural Gas: A Review" by Kirk W. Sherwood, James D. Craig at: www.eia.dow.gov/emeu/international/gas.html.

[7] Natural Gas Supply Association, Natural gas overview at: www.naturalgas.org/overview/resources.asp.

The major market proposed for Alaskan natural gas is domestic. Natural gas enters the domestic market through pipelines or imported via tanker as liquid natural gas (LNG). Currently, all North American LNG import/re-gasification facilities are located on the east and gulf coasts. While a small number of re-gasification facilities may be built on the west coast, any significant increase in LNG imports there will require additions to the pipeline infrastructure to transport natural gas eastward to market.

Regardless of form, natural gas competes with other energy sources in the broader marketplace. While it is better suited than other fuels for some uses, it is competitive or non-competitive for others. For instance, some utility plants may be built to use only one type of fuel while others may be designed to easily convert between fuel types. Most single fuel plants are convertible to other fuel types including natural gas. The largest current use for natural gas is industrial whereas the major increase in natural gas demand in the foreseeable future is for electric generation.[8]

The Energy Information Administration's (EIA – of the U.S. Department of Energy) energy outlook to 2030 presents a wide range of forecasts for natural gas demand.[9] Their own forecast shows an overall domestic natural gas demand increase of 0.8% per year from 2004 levels. Most of the demand growth will be in electric power generation which will overtake industrial uses as the highest use category. LNG imports are projected to grow at over 8% annualized and by 2030 consist of approximately 16% of domestic dry gas production (gas supplied by pipeline).

Natural gas supplied by pipeline is able to fill both base and peak load supply niches. While constant product flow is preferred, production is to some extent flexible both seasonally and based on peak demand during shorter periods.

Due to cost factors and infrastructure requirements, LNG has filled a base supply niche; i.e., LNG product flow requirements (e.g., shipping, forward time planning requirements, capital infrastructure) have mandated that it be sold in consistent quantities for constant end user demand. This has precluded it from being the peak load energy source. The market ramification of this requirement is that LNG does not necessarily achieve the marginal market price[10], but is generally bought and sold under long term (multi-year including decadal) contracts. However, as world LNG markets evolve, it could become the marginal supply. In the 1980s LNG contracts were long-term contracts with specified destinations and no short-term sales. Since the mid1990s this has changed as LNG suppliers offered more favorable terms, with the possibility of short-term sales. By 2002

[8] American Gas Foundation, February 2005. Natural Gas Outlook to 2020.

[9] Energy Information Administration, February 2006. Annual Energy Outlook 2005 with Projections to 2030. At: www.eia.doe.gov/oiaf/aeo/index.html

[10] The marginal market price is the price at which the volume demanded equals the amount supplied. If one considers a market where numerous sales and purchases are occurring, and each buyer and seller can negotiate terms, the marginal market price would be the last transaction price that insures all the volumes are bought and sold.

short-term sales represented about 8% of total LNG sales[11]. With LNG consumption forecast to almost triple by 2020[12], it is quite possible LNG could provide "spot" cargoes and thus provide marginal supplies.

Regardless of where ANS gas is delivered, it will be in a volume too large for the local market. If delivered into the Canadian pipeline system in Alberta, or the domestic system near Chicago, it will be transported through existing pipeline systems to additional markets.

VI. Geography and Infrastructure

In a competitive market the price of a good is determined by the forces of supply and demand. At a given price any commodity will enter the market if the cost of bringing it to market is less than the market price. Accordingly, commodities will continue to enter a market until the price falls to a level that is just sufficient for the last source to enter the market at a profit. Thus the lowest cost sources will enter the market first, followed by the next lowest one, etc. The higher cost sources are priced out of the market. The market price represents the cost of the last source to enter the market.

One of the most important determinations of the differences in costs between competing gas reserves is transportation cost. Transportation cost is a direct function of distance to market and geography.

Transporting Alaskan natural gas to a market requires building infrastructure to a market outlet. In the case of the Sponsor Group proposal, the closest significant pipeline infrastructure is in Alberta. But in a decade from now it may not have sufficient capacity to handle all the Alaska gas. Therefore, some increase in pipeline capacity could be required between Alberta and Chicago.

The distance between the North Slope and Chicago is nearly 4,000 miles. Generally, if the gas source is at tidewater, and the destination is tidewater, the most efficient way to transport natural gas over very long distances is with LNG. As gas is cooled and becomes LNG, it is much more compact; the energy density is increased. Unfortunately, liquefying the gas, shipping it, and re-gasifying it are expensive. It is only efficient relative to pipeline transport when distances are very long, and the liquefaction costs per mile are reduced. (The breakeven point depends on relative pipeline, liquefaction, and shipping cost, but is probably around 3,000 miles[13].) In 2005 the longest pipeline in the world was 4,100 kilometers in length (about 2,550 miles) extending from Russia to Western Europe.

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[11] US Energy Information Administration, "The Liquefied Natural Gas Market: Status & Outlook", December 2003, pages 38-40.
[12] Petroleum Economist, "Warnings of Limits to Growth", November 2005.
[13] Cornot-Gandolphe, Appert, Dickel, Chabrelie, Rojey, "The Challenges of Further Cost Reductions for New Supply Options (Pipeline, LNG, GTL)", IGU, WGC 2003, Tokyo, Japan, June 4, 2003.

Unfortunately North Slope gas is located 800-miles from tidewater, and there are no large competitive liquid natural gas markets at tidewater on the North American West Coast.

LNG shipments from the Middle-East to the U.S. are less expensive than a pipeline from the North Slope to the Upper Midwest, despite the longer distance. Qatar's gas travels about 8,300 nautical miles from Qatar to New York. The North Slope gas is about 4,000 miles from Chicago. However, Qatar has a lower cost of transportation (per BTU) because its LNG facilities are on the water's edge and transportation only involves tankers. Wood Mackenzie, an energy consultant group retained by the State, estimates that Qatar's transportation costs are about $1.25 per million BTU to the east coast of the United States. If the pipeline project to Chicago came in on budget, the projected transportation cost would be about $2.20 per million BTU – nearly 80% higher than the Qatar LNG cost estimate.

A pipeline transporting ANS gas could have a distinct cost disadvantage to other gas pipelines. A pipeline through Alaska and portions of Canada will be a more expensive operation than a pipeline through many other types of terrain. This is due to the higher construction and operating costs that the environment places on operation and maintenance.

Thus, North Slope gas could be one of the most expensive resources in the world to bring to market, which would put it near the bottom of the list for competitiveness and incremental introduction into the market. Other gas that is less expensive to transport to market could reduce the market price of gas, leaving a North Slope gas project at risk of losing money.

VII. Price Forecast

As described above, in a competitive market the price represents the cost of the last source to enter the market.

Natural gas has the same essential chemical characteristics regardless of origin and whether it is piped or undergoes re-gasification from LNG. Therefore, natural gas is fungible for end users and facilities do not need to be calibrated to the characteristics of the specific source. This means that the transport method does not affect demand nor does the source of product.

There are many price forecasts, and they have a wide range. The EIA's last published long run forecast[14] calls for increased drilling, new production, and increased LNG imports such that prices initially decline, and increase after 2011. They forecast LNG imports increasing from 1.4 tcf in 2004 to 4.4 tcf/yr in the reference case in 2030.

The EIA presents three scenarios with equal emphasis: reference case, rapid technology, and slow technology. Technological progress affects natural gas production by reducing

[14] Energy Information Administration, February 2006. Ob cit.

production costs and expanding the economically recoverable resource base. In the rapid technology case they state:

> The rapid technology case assumes 50% faster technology progress than in the reference case, resulting in lower development costs, higher production levels, lower wellhead prices per thousand cubic feet, increased consumption of natural gas, and lower LNG imports than in the reference case. In the rapid technology case, lower wellhead prices for natural gas lead to increased consumption and lower import levels.

Their forecast, in constant 2004 dollars is:

Scenario / Year	2010	2020	2030
Rapid Technology	\$4.81	\$4.22	\$5.35
Reference Case	\$5.03	\$4.90	\$5.92
Slow Technology	\$5.24	\$5.30	\$6.36

It is **not** reasonable to believe that today's high natural gas prices will continue over a 40 year period. It is equally not reasonable to believe we can forecast prices over that period. One should keep in mind that natural gas prices were regulated at a relatively low price level for close to 60 years in the last century which encouraged certain industries and facilitated the construction of a great deal of infrastructure. This infrastructure included pipelines to transport the natural gas and production facilities to produce goods from the natural gas, or furnaces to use the gas to heat residential and commercial facilities. History teaches us that unexpected events (including deregulation) will occur which may have a major bearing on price and cost. We just do not know *which* events. The U.S. has recently witnessed the relatively short term effects of a natural disaster on natural gas prices. With infrastructure in place and consumption patterns set during a period of regulation, it is not surprising that (after deregulation) there is limited demand response with a concurrent spike in prices associated with the disaster. This means that consumption of natural gas did not change that much in the short-run, while supplies were reduced significantly by the hurricane. Since the price of natural gas is the balancing factor that changes as consumption and supply change, the price increased dramatically because consumption was relatively fixed while supplies were decreasing.

Longer term effects associated with the high natural gas prices could occur due, for instance, to the perfection of nuclear fusion, driving the cost of producing a BTU of energy to a fraction of what it is today. Even without technology advancement, the substitution or a relatively abundant and low cost fuel, such as coal, may occur. In fact, the most recent long run outlook by the US Department of Energy[15] projects electricity generation from coal fired power plants will grow faster than electricity generation from

[15] US Department of Energy, Energy Information Administration, Annual Energy Outlook 2006 With Projections to 2030", February 2006.

gas fired power plants [2.5% versus 1.7%]. The effect will be that the share of electricity generated from natural gas will decrease from 18% in 2004 to 15% in 2030.

While the discussion has focused on long-term effects, some of the short term responses to the high prices have started to occur as consumers reduce their use of natural gas. There has been substitution of oil for gas in electricity generation, while there has been a warmer than normal winter. The combination has been lower than expected gas consumption which has led to a 59% drop in natural gas prices to $6.31 per million BTUs at the Henry Hub spot market on March 9, 2006 [from $15.39 per million BTUs at the Henry Hub spot market on December 13, 2005].

However, it is also *not* difficult to imagine that the development of 6,000-7,000 tcf of proven natural gas reserves worldwide could exert downward pressure on price. Cambridge Energy Research Associates (CERA) estimates that vast reserves of LNG could be landed in the U.S. at a price varying between $2.75 and $4.00 per mmBTU. If LNG became the marginal supply of gas, this would become the market price. It is the price at which any gas from Alaska would have to compete on a delivered basis.

VIII. Scale of Project

Pipelines are a textbook example of economies of scale. The best way to reduce the unit cost of transporting product through a pipeline is to increase the size of the line. Given the ANS natural gas reserve base, analysts estimate that the efficiency of North Slope economics is maximized by scaling up to the 4 bcf/d size pipeline. Although the per-unit costs are lowered, increasing the size adds to the total capital cost. This has resulted in a very large costly project, estimated at $21 billion.[16]

The $21 billion is the estimated cost to construct a pipeline to Chicago, however, there is the option to construct a pipeline to Gordondale, Alberta and purchase Firm Transportation [FT] commitments on other pipelines to Chicago, Illinois. Should the project sponsors elect to purchase FT commitments to Chicago, there would be another large capital cost[17] – the rather large cost for FT commitments for shipping 4 bcf/d. As an intermediate option, the project sponsors may choose to purchase some FT commitments for some of the gas, and construct a smaller pipeline on to Chicago. In any scenario, the gas has to be moved to Chicago. The total cost is likely to be $21 billion whether the option selected is [1] a large pipeline all the way to Chicago; [2] a large pipeline to Gordondale and FT commitments from Gordondale on to Chicago; or [3] a

[16] The capital costs for an LNG project are not dissimilar. In addition, the LNG project would carry the shipping burden. If the LNG were delivered to a U.S. destination, this would require the use of Jones Act LNG tankers, which would be expected to cost more than that of foreign tankers, exacerbating the non-competitiveness of the Alaska gas.

[17] Purchasing firm transportation commitments is an expenditure that is capitalized.

large pipeline to Gordondale, a smaller pipeline on to Chicago in conjunction with FT commitments from Gordondale to Chicago[18].

Very large construction projects create their own additional risk. Not only are ordinary cost overruns very expensive, but the logistical and technological complexity increases the probability of very large cost overruns. The record of very large cost overruns (over 100%) on large projects is extensive.[19]

Issues that can become particularly troublesome for large projects include:

- Contingency set asides
- Permitting delays
- Design changes
- Currency fluctuations
- Interest rate increases
- Changes in technology
- Material shortages
- Project labor agreements
- Material cost increases
- Construction safety concerns
- Unanticipated environmental issues

In the case of the Sponsor Group project, the future cost of steel presents an additional significant risk factor. Since the cost was estimated in 2001, steel prices have doubled.

Also, there is often a lack of personnel and skills to undertake the large projects. In addition, the projects are so complex they either distract management from other projects, or management cannot sufficiently focus on the project.

At $21 billion, the risk of losing money could be financially catastrophic to a small firm participating in the project. For the three large oil companies [BP, ConocoPhillips and ExxonMobil], their potential losses – should the project fail – would be about $15 billion and represent about 30% of their combined profit for 2004.

Small projects may carry a "nimbleness" premium despite their reduced efficiency.[20]

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[18] Firm transportation commitments from Alberta to other markets in Canada and the lower 48 states could be purchased, but Chicago is presented to allow a comparison with the proposed project.

[19] See, for example, Flyvberg, Bent, Bruzelius, Nils, and Rothengatter, Werner, Megaprojects and Risk: An Anatomy of Ambition, Cambridge University Press, Cambridge, United Kingdom, 2003.

[20] Operating costs can be viewed in general terms of cost per BTU delivered. Either a pipeline or LNG project in Alaska has the capacity to deliver about 1/3 of the BTU's per day that the TAPS does at full capacity. Even with the TAPS averaging half capacity the gas system would deliver less BTU's per day. However, the complexity of the gas transportation system, either a pipeline system roughly four times the length of TAPS or its same length combined with LNG plants, tanker transportation systems, and subsequent pipelines, will be more expensive to operate than the TAPS line overall and much more so on a BTU basis. This results in higher overall transportation costs for ANS natural gas than for oil.

IX. Competition Among Projects Worldwide

Regardless of price, any ANS gas project has to compete against other projects throughout the world for construction materials, priority and financing. Corporations have finite budgets. Only the best projects get funded subject to portfolio management constraints. The major factors of consideration include plans for product development and extraction over time, market constraints, competition, and long term profitability.

PFC Energy conducted a study for the State of Alaska examining the gas pipeline project in the context of the global portfolios that the three Sponsor Group companies have the opportunity to develop.[21] Taken together, the Sponsor Group companies have about 300 new projects and additional mature assets on their development planning horizon. The study was conducted in 2004 and assumed a $22 per barrel oil price.

The study viewed the Alaskan pipeline project from the viewpoint of the individual companies based on their assets and individual investment matrices. The concept of net present value per investment dollar and return on capital employed form the floor upon which investments must be compared. The lower the rating, the lower a project's ranking and the longer delay each company is willing to give it. Two different project lengths, pipelines ending in Gordondale, Alberta or Chicago, Illinois were considered. Based on the net present value per barrel of oil equivalent (a BTU comparison) and per dollar investment, the gas pipeline ranked as follows:

	Chicago	Gordondale
- ExxonMobil	74 out of 100	63 out of 100
- BP	61 out of 77	56 out of 77
- ConocoPhillips	49 out of 61	41 out of 61

These poor rankings reflect Alaskan/Canadian geography and construction challenges, the magnitude of capital construction costs, and subsequent operating cost disadvantage, and the State's regressive fiscal regime. It is reasonable to assume that even if other companies owned the North Slope leases the comparative outcomes would be similar.

PFC also analyzed the project with State participation as a 25% co-owner of the pipeline. Since active State participation results in shared financial risk, the priority of the pipeline project increases for each company. In each case, the priority increased, highlighting the fact that State involvement, or at least more conducive fiscal terms, increases project economic feasibility in the near term [see table below]. However, even with State participation, the Alaska projects are still ranked in the lower half of all but one project.

[21] PFC Energy, "North Slope Gas Projects in the Context of Global Portfolios," October 2004.

	Chicago	Gordondale
- ExxonMobil	62 out of 100	49 out of 100
- BP	55 out of 77	44 out of 77
- ConocoPhillips	40 out of 61	32 out of 61

X. Rate of Return

North Slope gas is far from market. Because of distance and geography, North Slope gas could be one of the most expensive resources in the world to bring to market. This would put it near the bottom of the list for competitiveness and incremental introduction into the market. Any other cheaper gas could reduce the market price, leaving North Slope gas producers at risk of losing money.

Over the last several decades, producers have been hurt by using high price forecasts. Accordingly, they "stress test" their projects by evaluating them at lower prices. We believe today that this "stress price" is about $3.50 per mcf in Chicago.

It is believed that very little Alaska gas will be sold in Alberta; it will be sold either in the Eastern United States, the Upper Midwest, or the Pacific Northwest. The producers will not spend over $14 billion to build a pipeline only to Alberta not knowing how they are going to get the gas beyond Alberta. Moreover, the producers, at *this* point in time, cannot assume there will be available capacity, given the uncertainty regarding additional Western Canada production that could come on line over the next decade.

Even if there is available pipeline capacity to take the gas beyond Alberta, they will need to obtain firm transportation capacity on it. This commitment is capitalized in the economic evaluations.

There will probably be some combination of available and new capacity that will be necessary to move the gas beyond Alberta. However, used capacity does not cost much less than new; old sections are often replaced and maintenance costs are considerable. Therefore, we have examined the economics based on a new pipeline from Alberta to Chicago.

The Department of Revenue estimates the rate of return on the capital investment for the Sponsor Group project to be 14.1% when natural gas prices are at $3.50 per mmBTU. This is lower than what most alternative developing projects will earn. With a 25% capital cost overrun the rate of return is reduced to 12.5%. With a 50% capital cost overrun, the rate of return falls 11.3%.

XI. Fiscal Stability

Another major component of costs is fiscal costs: the dollar amount producers will pay to the government in taxes and royalties. Regardless of fiscal terms today, major changes in fiscal terms after the pipeline is constructed could materially alter the project viability.

One of the goals of the Stranded Gas Act is to stabilize State fiscal terms in order to encourage marketing and new development of stranded gas. If the gas were marketed, it would provide additional royalty and revenue to the State of Alaska. If the gas is not marketed, there is no additional revenue to the State of Alaska.

Rates of return and overall project success are built on many factors including return of invested funds and timing. Major investments are much safer when the return on investment occurs earlier in a project. In accounting terms, this means that some types of deferred costs count against profitability less than those incurred earlier in the project. Stated differently, the ability to defer some costs allows recovery of other costs earlier and therefore can increase the fiscal viability of a project.

If the producers spend $21 billion to build the pipeline, the State, at any time, can remove the value from the project by changing the fiscal terms. The producers can take the risk to build the pipeline based on certain tax and royalty assumptions and the State can, by an act of the Legislature, increase taxes to such an extent that risk of the project remains with the producers but the value of the project is transferred to the State. The State could take enough from the producers in taxes that the risk of losing money on the project substantially increases.

XII. Alaska LNG

Most of this analysis has focused on the Sponsor Group Alaska Canada pipeline proposal (ALCAN). The AGPA proposed project is very different from the Sponsor Group project: a pipeline about 800 miles to a port in south-central Alaska with associated LNG compression and tanker facilities. From these facilities the LNG would be transported by tanker to ports on the West Coast. This project would also require the construction of LNG re-gasification plants at receiving ports on the West Coast and pipelines to connect with existing distribution systems to move some of the gas to more easterly markets.

The LNG option is determined to be less viable than the pipeline proposal – which means this project may not "un-strand" the gas on the North Slope. The reasons are threefold:

- First, it appears very likely that the proposed LNG costs would be higher than the pipeline costs.
- Second, it appears very likely that the prices received at the sales point would be lower for the LNG option.
- Third, it appears very unlikely that any of the proposed receiving terminals will be built.

The latest proposal from the Alaska Gasline Port Authority[22] calls for 1 bcf/d delivered to each of Kitimat, B.C., Bradwood, Oregon, and Pendleton and Ventura, California. Much of this discussion is based on an analysis by PFC Energy[23].

[22] "All Alaska Gasline/LNG Project Agreement" submitted by the Alaska Gasline Port Authority on August 22, 2005.

A. Costs

The Port Authority proposal includes the capital costs within Alaska of getting North Slope natural gas to tidewater, i.e., the conditioning plant, pipeline, liquefaction and LPG extraction facilities, and port facilities. However, there will be considerable additional expenses to transport the LNG to market: a) shipping, b) re-gasification, and c) new inland pipelines. Estimates by PFC reveal that, in total, it would cost an extra $1.03 per million BTU to transport natural gas to the West Coast via LNG including re-gasification, relative to the ALCAN project.

There are multiple reasons for this cost difference. Some of the major reasons include differences in transportation modes and associated cost and the necessity of conversion to LNG and re-gasification after shipping.

Under the Jones Act anything shipped from an American destination to another American destination must be carried on a ship built in the United States, on a ship with a U.S. flag, and staffed by a U.S. crew. In the case where Alaska gas may go to Canada or Mexico for re-gasification and marketing back to the U.S., the Jones Act also applies. The only possible exemptions appear to be for national defense. Re-flagging old U.S. built LNG tankers that have been operating overseas under foreign flags is clearly precluded in the Act.

There are no U.S. shipyards that build LNG tankers. The start-up and construction costs would be high, even for shipyards that are experienced in constructing naval vessels or oil tankers. In the oil trade Jones Act tankers cost more than twice as much to build and operate compared to foreign tankers. There are three main reasons for this: first, U.S. labor costs are higher than foreign. Second, there is little or no competition between shipyards in the U.S. to contain costs. Third, the simple lack of experience and "assembly-line" structure causes inefficiencies. Thus in the case of LNG there is every reason to believe the shipping costs for Alaska LNG would be significantly greater than shipping LNG from foreign jurisdictions. PFC estimated Jones Act tankers would cost 54% more than foreign tankers.

B. Price

As already mentioned, the current Port Authority proposal is to land 4 bcf/d of LNG at four distinct West Coast re-gasification plants. None of these plants are in an advanced stage of permitting and none of them appear likely to be constructed at this time.

Moreover, and most important, the economics of the LNG project are dependent on being able to market 4 bcf/d in order to bring the unit costs down to a reasonable level. The problems of marketing 4 bcf/d of North Slope gas as LNG are very serious.

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[23] PFC Energy, "Assessment of the Alaska Gasline Port Authority LNG Project," prepared for the Alaska Department of Revenue, March 17, 2006. The study also examined Long Beach, California as a possible destination.

The West Coast is a rather isolated market. There is insufficient East-West infrastructure in place to move excess supplies out of the market. Most forecasts project about 2 bcf/d of additional supplies may be required in the next 10-15 years[24]. Shell and BP have already committed to supply Sempra a combined 1 bcf/d of Asian and Australian gas, and Sempra recently conducted an open season to procure the balance. Attempting to sell all 4 bcf/d of Alaska gas in the West Coast market would be a challenge as the Alaska gas would be competing with lower cost competitors.

Moreover, this market will grow incrementally, not all at once. Placing the entire 4 bcf/d into the market at once will be particularly difficult. However, because of the large fixed cost of the pipeline it is necessary to market all of the gas rather quickly. Projects that do not have that large fixed cost, and can put smaller amounts of gas into the market over a shorter time, will have an advantage. Placing 4 bcf/d on the West Coast market would drastically suppress prices.

PFC estimates that 4 bcf/d landed on the West Coast would affect the supply balance such that it would command $0.61/mmbtu less than the same volume landed in Chicago. This is attributable to:

- Much of the gas is landed in next exporting regions. The gas must travel considerable distances to market areas or compete with other sources of supply transiting the region to serve local demand.
- As mentioned above, the size of the incremental supply relative to the market weighs on the West Coast price.

PFC's projection is contingent on the timely construction of West-East pipeline infrastructure to move excess supplies from the region. They warn:

> PFC Energy expects that given the lead time required for either Alaskan gas transportation project, companies would incorporate the incremental supplies in their pipeline planning activities, smoothing the transition. If companies do not do so, then the introduction of Alaskan supplies could prove more disruptive than indicated here, and price discounts for the new gas supplies would be greater than projected here.

As for supplying Asian markets with LNG, it appears unlikely that North Slope gas could compete with the plethora of closer tidewater sources that do not have to build an 800-mile pipeline just to reach the coast.

C. Siting Issues

PFC concluded that it is unlikely any of the proposed U.S. or Canadian West Coast LNG receiving terminals will be built. They rated the likelihood of construction of any of the

[24] This includes forecasts from Cambridge Energy and the California Energy Commission.

terminals in the next decade at poor to negligible, based on environmental, community, permitting, financing, and market issues.

D. Netback Comparison

Between the additional cost and the reduced price, PFC estimates the netback value would be $1.64/mmbtu ($1.80/mcf) less for the LNG project relative to the ALCAN project. This would be $10/bbl less on an oil-equivalent basis.

XIII. Conclusion

Stranded gas is gas that is not being marketed due to cost and price conditions. North Slope gas today certainly fits this criterion. This paper summarizes many of the reasons and presents analysis conducted by the Department of Revenue. The commercialization of North Slope gas will be subject to market forces. Markets fluctuate with the lowest cost supplies coming in to the market first. The cost of these supplies set the price. Higher cost supplies are shut out until the lower cost supplies are depleted.

It has been shown that the reason North Slope gas has not been marketed is the distance from market coupled with Alaska's geography, the existence of vast supplies of lower cost gas in other parts of the world, and the problem that other supplies are not subject to the size risk inherent in the North Slope project. These are the cost and price conditions that are at risk of prevailing during the period in which this project will operate. Therefore, the Department of Revenue concludes that Alaska's North Slope natural gas is stranded.

BP Testimony

House Resources Committee

June 3, 2006

Thank you for the opportunity to testify this morning. For the record, my name is David Van Tuyl. I work for BP as the commercial manager of the Alaska Gas group. It's a privilege for me to be able to offer my testimony on HB-2004. We support the intent behind the bill which provides amendments to the Stranded Gas Development Act, and believe this bill will help progress the gas pipeline fiscal contract.

The Administration did a good job in structuring these amendments and in explaining them to this committee. However, there is one point that we see a bit differently than the Administration, and that we'd like to take a moment to clarify for the record. The Administration stated that the amendment to AS 43.82.220(a) paragraph (2) that allows for the inclusion of terms in the contract related to the State reimbursing the producers for certain upstream costs was required because this was not a right the producers currently hold under either existing lease or unit agreements. We don't agree. In old form leases (known as "DL-1" leases). the State is obligated to pay for upstream costs associated with any of its gas it takes in kind. So we feel that this is a lease right associated with these DL-1 leases. The vast majority of the known North Slope gas resource, around 90%, is found on these DL-1 leases. The fiscal contract simply extends that existing lease right to all gas from all leases.

To conclude my brief comments, I want to emphasize that BP stands ready, willing and able to advance the gas pipeline project, along with our partners ConocoPhillips, ExxonMobil and the State of Alaska. The gas pipeline fiscal contract, coupled with HB-2004, makes that objective possible. BP also stands ready to work with the legislature as you complete your work on this bill.

We support passage of HB-2004, and then encourage the legislature to approve the gas pipeline fiscal contract to enable all Alaskans to benefit from one of the largest energy projects on the planet.

Thank you for the opportunity to testify. I'd be happy to try and answer any questions you might have.

Jun 1, 10:47 PM EDT

Hearings begin on changes to Stranded Gas Act

By ANNE SUTTON
Associated Press Writer

JUNEAU, Alaska (AP) -- Hearings began in the state House and Senate Thursday on legislation meant to move forward Gov. Frank Murkowski's contract with three oil companies to develop the North Slope's natural gas reserves.

The House Resources Committee began taking testimony on a measure that would amend the state's Stranded Gas Development Act, the law under which the governor negotiated the contract's fiscal terms with ConocoPhillips, Exxon Mobil Corp. and BP PLC.

The bill, introduced by the governor on Wednesday, would allow the state to take gas in place of tax payments as part of its 20 percent ownership in the proposed gasline. It would also lock in the producers' tax and royalty rates by 30 years for oil and 45 years for gas. The oil companies have said that kind of tax stability is a condition to them building a North Slope natural gas pipeline.

Kevin Jardell, the governor's legislative liaison, told lawmakers the changes would smooth the way toward final ratification of the contract.

But lawmakers have opposed the governor's proposal to freeze the producers' tax rates.

After the committee meeting, co-Chairman Ralph Samuels, R-Anchorage, said the administration should have the authority to negotiate gasline terms for the state, but locking in the tax rates is another matter.

"I don't have any problem with their ability to have those tools, but the oil tax, that's taking a tool away from us. That's a different story," he said.

Samuels said he and other lawmakers are discussing how best to modify the tax rate provisions. One idea has been to create a "reopener" clause that would allow lawmakers to change the tax rates in the future if economic conditions call for it.

Lawmakers were also concerned that the governor may bypass their efforts to pass a tax rate that is higher than the one he has proposed. A proposal to tax the Alaska profits of oil companies is also before lawmakers in special session after the measure failed in the regular session.

Murkowski wants to set the oil production tax at 20 percent. Lawmakers have considered a number of different rates between 20 and 25 percent.

Asked by House lawmakers if the final contract would contain whatever terms pass the Legislature, Jardell said he could not give a definitive answer.

"Our position is the Legislature needs to set the rates and we will take them to the bargaining table to negotiate from those rates," he said.

Lawmakers also had concerns about a proposed amendment to the section that requires the Commissioner of Revenue act in the best interest of the state. The language was modified to read the "long-term fiscal" interests of the state.

Rep. Harry Crawford, D-Anchorage, said the change could be read to say that any deal would be a good deal.

"It gets them a 'get out of jail free' card," he said.

The administration said the change was made in order to make the language consistent with other parts of the law.

Meanwhile, the newly formed Senate Special Committee on Oil and Gas, made up of members of the Senate Resources and Finance Committees, also began hearing the bill on Thursday.

The committee also took testimony on another measure that would create a public corporation within the Department of Revenue called the Alaska Natural Gas Pipeline Corporation.

Committee hearings are expected to continue over the weekend.

It could be near the end of July before the final terms are back before the Legislature.

A 45-day public comment period on the natural gas contract is currently under way, and the governor has said he will extend that if need be. The Commissioner of Revenue then will have 30 days to consider the comments and proposed amendments before issuing a final determination. That's when the Legislature must decide whether to ratify or reject the contract.

Fairbanks Daily News-Miner

Changes to Stranded Gas Act weighed
By R.A. DILLON

Friday, June 02, 2006 - Staff Writer

JUNEAU--Alaska legislators on Thursday took up amendments to the state's Stranded Gas Development Act.

Gov. Frank Murkowski is asking lawmakers to approve changes that would allow him to lock-in the producers' taxes and royalty for 30 years on oil and 45 years for gas, as well as take the state's share of production in natural gas instead of cash.

The 10-page bill contains more than a dozen alterations to the Stranded Gas Development Act, the law under which Murkowski negotiated a deal with Exxon, BP and ConocoPhillips to develop the North Slope's 35 trillion cubic feet of gas reserves.

Kevin Jardell, Murkowski's legislative director, said the amendments provide the administration with greater authority to negotiate the terms of the contract with the producers.

Murk-owski has been in talks with the producers for nearly two years but the proposed deal goes beyond the limits of the stranded gas act, so he needs lawmakers to amend the act to make the contract legal.

Jardell and other administration officials provided members of the House Resources Committee and the newly formed Senate Special Committee on Natural Gas Development a page-by-page walkthrough of the amendments. The amendments would:

* Repeal language in the Stranded Gas Act that prohibits significantly altering tax and royalty rates on existing oil and gas production.

* Allow the state to take royalty and production tax on gas in-kind instead of cash.

* If approved, the final contract would override the state's existing leases on the North Slope.

* Require the state to agree to arbitration to settle all disputes with the producers and prohibit the state from taking the companies to court.

While some of the changes are likely to receive the approval of lawmakers, others face a much tougher battle, said House Resources Co-Chairman Ralph Samuels, R-Anchorage.

"We're not going to lock oil in for 30 years," he said. "That we can't do."

Lawmakers have been consistent in their opposition to freezing taxes on oil for the life of the contract, something the producers argue is needed before they can invest billions of dollars to build a gas pipeline from the North Slope to markets in Alberta, Canada, and perhaps Chicago. The state needs time to make sure the new tax system works and no one can guarantee the future price of oil, Samuels said.

"Nobody's crystal ball is perfect; not even the industry's," he said.

Samuels said he would try to remove or alter the provision before the bill leaves his committee.

Sen. Ralph Seekins, chairman of the Senate Special Committee on Natural Gas Development, said the Legislature may reduce the length of fiscal certainty to reduce the risk to the state.

"We can improve the economics of the pipeline without having to put a fixed date on it," he said.

Seekins said the chief concern was whether the Legislature should increase the powers the governor already has under the 1998 Stranded Gas Act to negotiate with the producers.

Samuels had fewer problems with granting the governor wider powers to negotiate a gas deal. The final decision still remains with the Legislature, he said.

"The point is, 60 people are never going to be able to negotiate a contract," he said, "so we are turning it over to the administration and if we don't like what they do, we vote it down."

Rep. Harry Crawford raised concern over the administration's attempt to change the requirement that the contract be in the "best fiscal interest" to the "long-term interest" of the state.

The Anchorage Democrat said the change would allow the administration to approve almost any contract.

"It gives them huge latitude on what is in the long-term interest of the state," he said. "That's a big difference to what's in the best fiscal interest of the state."

Jardell said the change was a minor technical amendment to make sure the language in the contract is consistent with the findings released by the commissioner of the Department of Revenue.

Crawford also objected to language in the amendments that would exempt the producers from tax increases passed through the public initiative process.

Crawford is one of the sponsors of an initiative on the November ballot that would tax leaseholders $1 billion a year if they fail to develop gas fields on the North Slope.

Crawford said he planned to meet with other members of the minority caucus to discuss possible amendments to the administration's bill.

House Resources will take up the amendments again today at 9 a.m. Samuels said he expects to have a committee substitute ready by Saturday and the measure could be passed out the same day.

Seekins, R-Fairbanks, said the special Senate gas committee would hear from the administration and the Legislature's legal advisers this morning and take public testimony starting at 9 a.m. on Saturday.

He said the committee would consider amendments Sunday, but he did not know when a committee substitute might be introduced.

The special session must end no later than midnight on June 8.

"If we don't hit that deadline, we don't hit it," he said. "This is too important to hurry."

The governor can call a second special session beginning June 9 if he wants to keep lawmakers working on the gas contract.

Staff writer R.A. Dillon can be reached at (907) 463-4893 or rdillon@newsminer.com .

LEGAL SERVICES

DIVISION OF LEGAL AND RESEARCH SERVICES
LEGISLATIVE AFFAIRS AGENCY
STATE OF ALASKA

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FAX (907) 465-2029
Mail Stop 3101

State Capitol
Juneau, Alaska 99801-1182
Deliveries to: 129 6th St., Rm. 329

MEMORANDUM June 4, 2006

SUBJECT: Purchase of a gas pipeline sponsor's share (HB2004; Work Order No. 24-GH2046)

TO: Representative Jay Ramras
Attn: Jane

FROM: Dennis C. Bailey DB
Legislative Counsel

You have asked whether the purchaser (an LLC) of a pipeline sponsor's share of an interest in the pipeline would be responsible for state income and other taxes. Although you mentioned an "individually owned" LLC, the ownership structure is not a deciding factor in answering your question.

The short answer to the question is if the sponsor/seller was liable for state income taxes and other taxes, the purchaser would also be responsible for the taxes unless the contract or purchase agreement provides otherwise.

In order for an interest in a contract to be purchased, the contract interest must be assignable. A contract may allow or prohibit assignment or restrict assignment of a party's interest. The Stranded Gas Development Act addresses the issue of assignment in AS 43.82.260. It provides:

> Sec. 43.82.260. Change of parties to an application or a contract; assignment of interests.
>
> (a) A qualified sponsor or member of a qualified sponsor group may assign an interest in or add or withdraw a party to an application under AS 43.82.120 only if the commissioner has
>
> (1) made a finding that the assignment, addition, or withdrawal is consistent with the requirements of AS 43.82.110; and
>
> (2) given prior written approval for the assignment, addition, or withdrawal.
>
> (b) A contract developed under this chapter may provide for the assignment to or withdrawal of a qualified sponsor or member of a qualified sponsor group.
>
> (c) Upon being added to an application under this section, a party becomes a qualified sponsor or a member of a qualified sponsor group, as appropriate, for the relevant project.

(d) The commissioner may not unreasonably withhold approval under (a) of this section, but may condition the approval in any way reasonably necessary to protect the fiscal interests of the state and to further the purposes of this chapter.

(e) For purposes of this section, an assignment includes a transfer of stock or a partnership interest in a manner that changes control of a qualified sponsor or member of a qualified sponsor group.

In general terms, a purchaser undertakes the rights and the duties of the seller. If the seller is responsible for state income and other taxes, the purchaser becomes responsible, and vice versa. These terms may be negotiable within the purchase agreement, but may be affected by limitations on the assignment in the original agreement.

I have enclosed copies of the sections of the pipeline contract and the fiscal findings related to the contract that address this issue but I have not reviewed or analyzed them.

If I may be of further assistance, please advise.

DCB:ljw
06-259.ljw

Enclosures

PART G - RELATIONSHIP OF THE PARTIES

ARTICLE 31 - ASSIGNMENT, ADDITION AND WITHDRAWAL

31.1 Assignment and Addition of a Person.

(a) Assignment. A *Producer* may assign its rights, privileges and obligations in a *Property* under this *Contract* to a qualified *Person* ("Assignee") as provided in Article 31. A *Producer* may initiate an assignment by providing the other *Parties* a *Notice* that contains the following information:

(i) identity of the *Assignee*;

(ii) the rights, privileges and obligations that are assigned to the *Assignee*; and

(iii) any other information the *Producer* deem appropriate.

The *DNR Commissioner* shall approve an assignment of an interest in a *Property* from a *Producer* to a *Person* other than a *Producer* or an *Affiliate* unless the *DNR Commissioner* makes a written finding that the transfer would adversely affect the interests of the *State*. The *DNR Commissioner* may request additional information reasonably necessary to make the finding. An assignment of an interest in a *Property* from a *Producer* to an *Affiliate* or to another *Producer* is effective upon *Notice*. Any other assignment is effective upon approval by the *DNR Commissioner*.

(b) Additional Person. A *Producer* shall add to this *Contract* any *Person* that owns a *Midstream Element* in which one or more *Producers* or their *Affiliates* have an interest

("Additional Person") by providing a *Notice* to the other *Parties* that contains the following information:

(i) a brief description of the reason for adding the *Additional Person*;

(ii) the identity of the *Additional Person*;

(iii) the rights, privileges, and obligations that are assumed by the *Additional Person*; and

(iv) any other information the *Producer* deems appropriate.

The rights, privileges and obligations of the *Additional Person* are subject to the conditions set out in Article 31.1(d). The addition of the *Additional Person* is effective upon *Notice*.

(c) Conditions Regarding Assignees.

(i) Except for *Assignees* under Article 31.1(c)(ii), an *Assignee* that is not an *Affiliate* of the assignor is subject to the following conditions:

(A) any obligation to pay *SCIT* is modified only by the adjustments provided under Articles 19.3, 19.4, and 19.5; and

(B) the exemptions and covenants provided the *Contract* are limited to *Taxes*, other than *SCIT*, on that portion of the *Assignee's* oil and gas related business activity in *Alaska* that has been assigned to it.

(ii) The conditions under Article 31.1(c)(i) do not apply to an *Assignee* that is:

(A) an *Affiliate* of the assignor; or

(B) another *Producer* or its *Affiliate*.

(d) Conditions Regarding Additional Person. For an *Additional Person*, the exemption and covenants provided in the *Contract* are limited to *Taxes*, other than *SCIT*, on that portion of the *Project* that has been assumed by the *Additional Person*.

31.2 Effect of Assignment, Addition, and Transfers.

(a) Rights, privileges and obligations of an Assignee or Additional Party. An *Assignee* and each *Additional Person* is deemed a *Participant* and, to the extent the rights, privileges and obligations are assigned or added, this *Contract* binds and benefits the *Assignee* and the *Additional Person*. A *Person* that owns an interest in a *Project Entity* is not a *Participant*, based on that ownership alone.

(b) Retained rights, privileges and obligations of the Producers and their Affiliates. Each *Producer* and its *Affiliates* retain all their rights, privileges and obligations under this *Contract* other than those assigned to an *Assignee* or assumed by an *Additional Person* under Article 31.1.

(c) Transfers.

(i) If the ownership of a *Producer*, or an *Affiliate* of a *Producer* that holds the ownership interests of all or substantially all of the *Properties* held by that *Producer* and its *Affiliates*, is transferred by sale of stock, merger, corporate reorganization, or similar transaction, that transfer is not subject to the limits in Article 31.1(c) or (d).

(ii) If a *Producer* and its *Affiliates* sell or otherwise dispose of all or substantially all of their *Alaska* oil and gas assets, that sale or disposition is not subject to the limits in Article 31.1(c) or (d).

31.3 No Fee for Additional Persons. No *Party* shall charge a *Person* a fee solely because the *Person* is becoming an *Additional Person* to this *Contract*.

31.4 Acquisition.

(a) Exhibit D Properties. If a *Producer* acquires or is assigned an interest in any *Property* listed on Exhibit D, the *Producer* may add its interest in that *Property* to Exhibit D.

(b) Leases not on Exhibit D. If a *Producer* acquires or is assigned an interest in an *ANS* lease not listed on Exhibit D, the *Producer* may add its interest in that lease as a *Property* to Exhibit D subject to the following limitations:

(i) if that lease was acquired in a *State* lease sale, that *Property* must be removed from Exhibit D if *Gas* from that *Property* is not delivered to the *Mainline* within fifteen (15) *Calendar Years* after the effective date of its addition to Exhibit D;

(ii) if that lease was acquired in a federal or private lease sale, that *Property* must be removed from Exhibit D if *Tax Gas* from that *Property* is not delivered to the *Mainline* within twenty (20) *Calendar Years* after the effective date of its addition to Exhibit D; and

(iii) a *Law* of general applicability providing for a uniform upstream fiscal contract is enacted substantially in the form of Attachment 1 ("Uniform Upstream Fiscal Contract Act").

(c) Notice. To add an interest in an *ANS* oil and gas lease to Exhibit D, a *Producer* shall provide a *Notice* ("Notice of Additional Property") to the *Commissioner*. That *Notice of Additional Property* must include the following information:

(i) the date the additional *Property* was acquired and the effective date of its addition to Exhibit D;

(ii) the *Producer's Working Interest* share of the additional *Property*; and

(iii) the other categories of information included in Exhibit D.

31.5 Withdrawal Before Open Season. Subject to Article 31.8, any *Participant* may withdraw from this *Contract* before the execution by the *State* of the binding precedent agreements associated with the initial *Open Season* to reserve transportation capacity.

31.6 Withdrawal After Open Season. Subject to Article 31.8, any *Participant* may withdraw from this *Contract* after the execution of the binding precedent agreements associated with the initial *Open Season* to reserve transportation capacity, provided that the *Withdrawing Participant* and its *Affiliates* have either assigned or otherwise relinquished and hold no interest, directly or indirectly, in any *Midstream Element* or in any *Property* before the *Participant's Notice* of withdrawal.

31.7 Notice and Effective Date. A *Withdrawing Participant* shall provide sixty (60) *Days* prior *Notice* of withdrawal to the *State* and to the other *Participants*. The withdrawal is effective upon the expiration of the sixty (60) *Day* period.

ARTICLE 31: ASSIGNMENT, ADDITION AND WITHDRAWAL

1. **Assignment of a Person**.

- A Producer can assign its rights, privileges and obligations in a Property to a qualified assignee by providing the other Parties notice with the following information: (i) identity of assignee; (ii) the rights, privileges and obligations that are assigned; and (iii) any other information the Producer deems important.

- The DNR Commissioner shall approve an assignment to a Person other than a Producer or an affiliate unless the Commissioner makes a written finding that the assignment would adversely affect the interests of the State.

- An assignment from a Producer to an affiliate or to another Producer is effective upon notice.

2. **Addition of a Person**.

- A Producer shall add any Person to the Contract owning a Midstream Element in which one or more Producers or their affiliates have an interest [or a Producer affiliate that owns an interest in an oil pipeline that will be subject to the payment in lieu of oil pipeline ad valorem taxes.]

- To do so, the Producer must provide a notice to the other Parties containing: (i) a description of the reason for adding the additional Person, (ii) identity of the additional Person, (iii) the rights, privileges and obligations assumed by the additional Person, and (iv) any other information the Producer deems appropriate.

- For an additional Person, the exemptions and covenants provided in the Contract are limited to Taxes, other than SCIT, on that portion of the Project that has been assumed by the additional Person.

3. **Conditions Regarding Assignees**.

- For assignees that are not affiliates of the assignor and additional Persons:

  (i) obligations to pay SCIT are modified only by the adjustments provided by Articles 19.3, 19.4 and 19.5; and

  (ii) the exemptions and covenants in the Contract are limited to Taxes, other than SCIT, on that portion of the assignee's oil and gas activity in Alaska that has been assigned to it.

- The above conditions do not apply (i) to assignees that are affiliates of the assignor or another Producer or its affiliate; (ii) if ownership of a Producer or affiliate is transferred by stock sale, merger, reorganization or similar transaction; and (iii) if a Producer and its affiliate sells all or substantially all of their Alaska oil and gas assets.

4. **Effect of Assignment, Addition and Transfers**.

- Each assignee and additional Person is deemed a Participant and the Contract binds and benefits both. A Person owning an interest in a Project Entity is not a Participant based solely on that interest.

- Each Producer and its affiliates retain all their rights, privileges and obligations other than those assigned or assumed.

5. **No Fee for Additional Person**. No Party may charge a fee solely because the Person is becoming an additional Party to the Contract.

6. **Acquisition**.

- If any Producer acquires or is assigned any interest in any Property listed on Exhibit D, the Producer may add its interest in that Property to Exhibit D.

- If a Producer acquires or is assigned an interest in any lease not listed on Exhibit D, the Producer may add its interest as a Property to Exhibit D subject to the following:

  (i) for leases acquired in a State lease sale, the Property must be removed from the Exhibit if Gas is not delivered to the Mainline within 15 years after its addition to the Exhibit;

  (ii) for leases acquired in a federal or private lease sale, the Property must be removed from the Exhibit if Tax Gas is not delivered to the Mainline within 20 years of its addition to the Exhibit; and

  (iii) a law of general applicability is enacted providing for a uniform upstream financial contract substantially in the form of Attachment 2 to the Contract.

- To add an interest in an ANS oil and gas lease to Exhibit D, a Producer must provide a notice to the Commissioner that includes the date Additional Property was acquired and the effective date of its addition to Exhibit D, the Producer's Working Interest share of the Additional Property, and other information required to be included in Exhibit D.

7. **Withdrawal**.

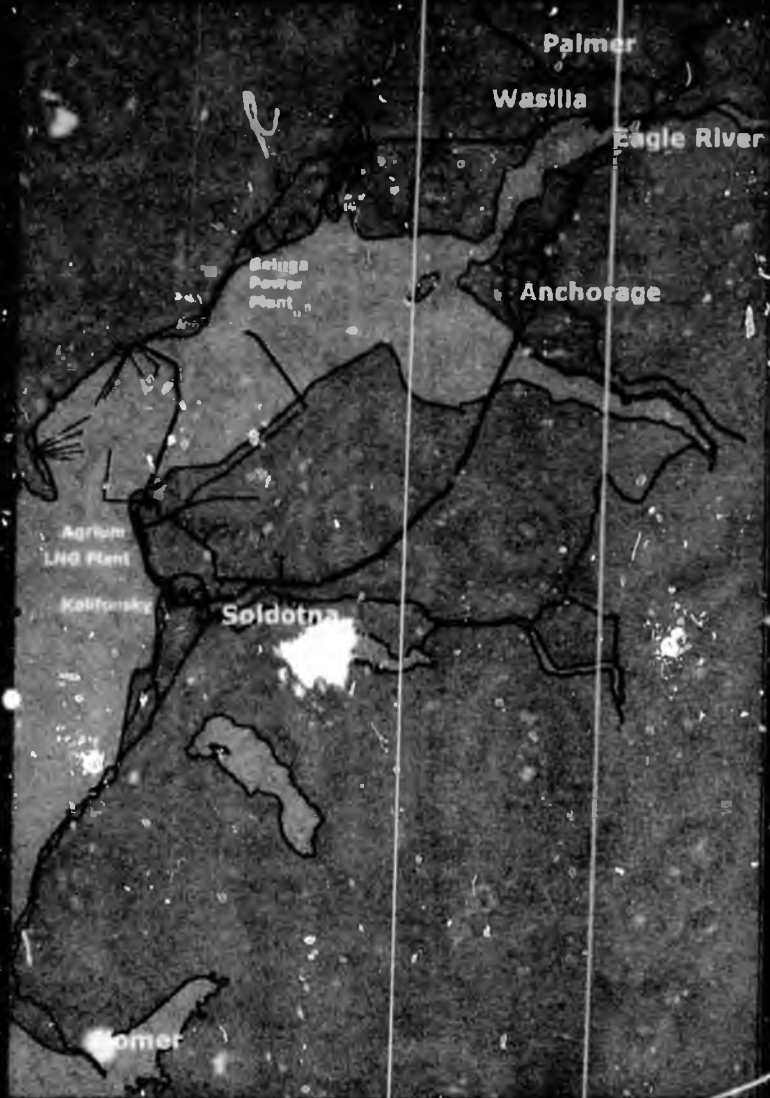
- Before Open Season. Any Participant may withdraw from the Contract before execution by the State of the binding precedent agreements associated with the initial Open Season to reserve transportation Capacity.

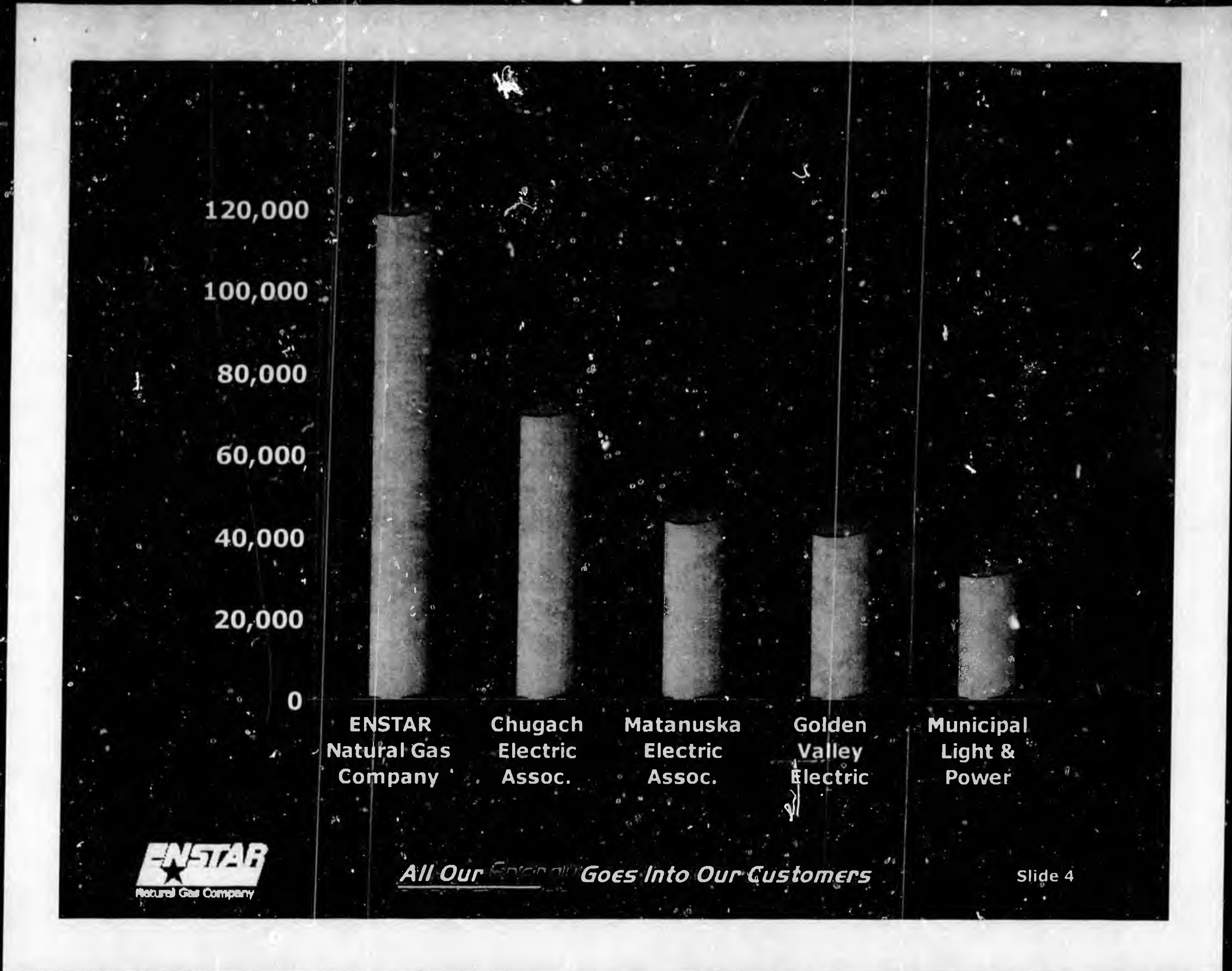
- After Open Season. Any Participant may withdraw after execution by the State of those precedent agreements, provided that it and its affiliates have either assigned

Presentation by ENSTAR Natural Gas Company
Tony Izzo, President

- For over 44 years ENSTAR has
  - Kept Alaskans Warm
  - Fueled business and industry
- ENSTAR serves half of Alaska's population; in Anchorage, Mat-Su, and Kenai Peninsula
  - Over 118,000 Meters or 318,000 Customers

- 393 miles of high-pressure transmission pipelines
- 2461 miles of gas distribution mains




120,000
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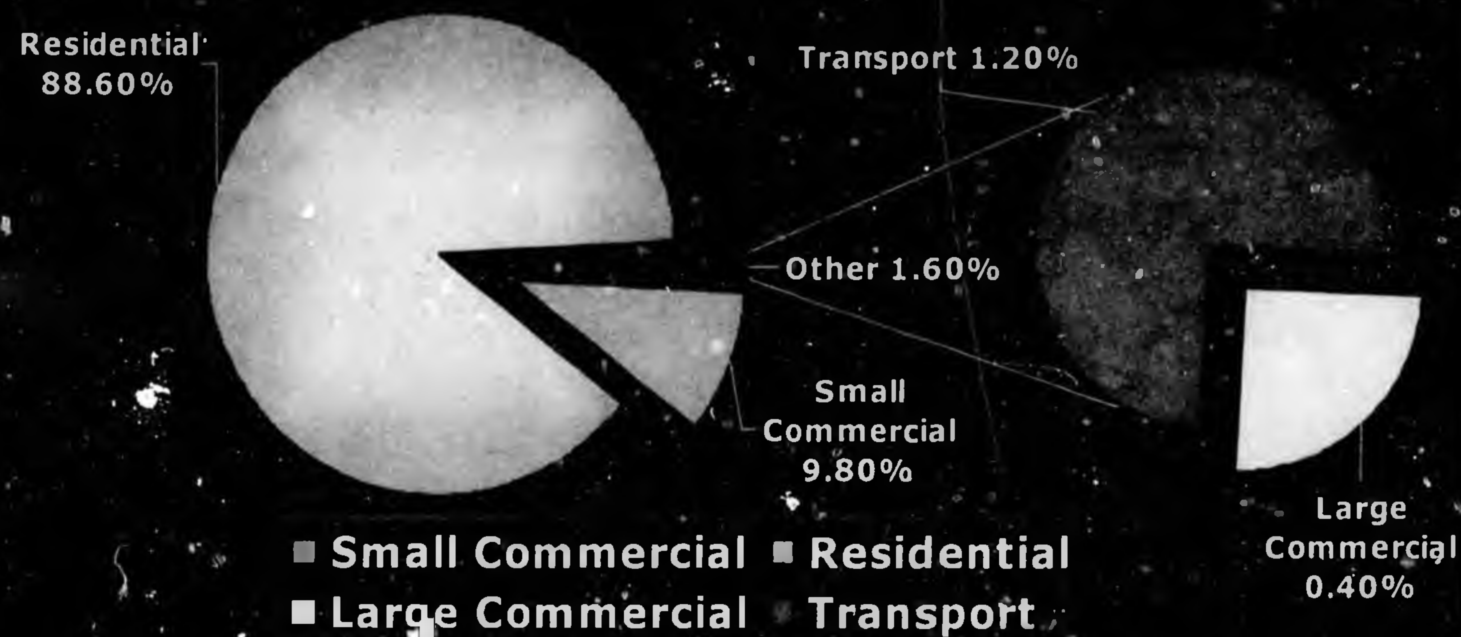
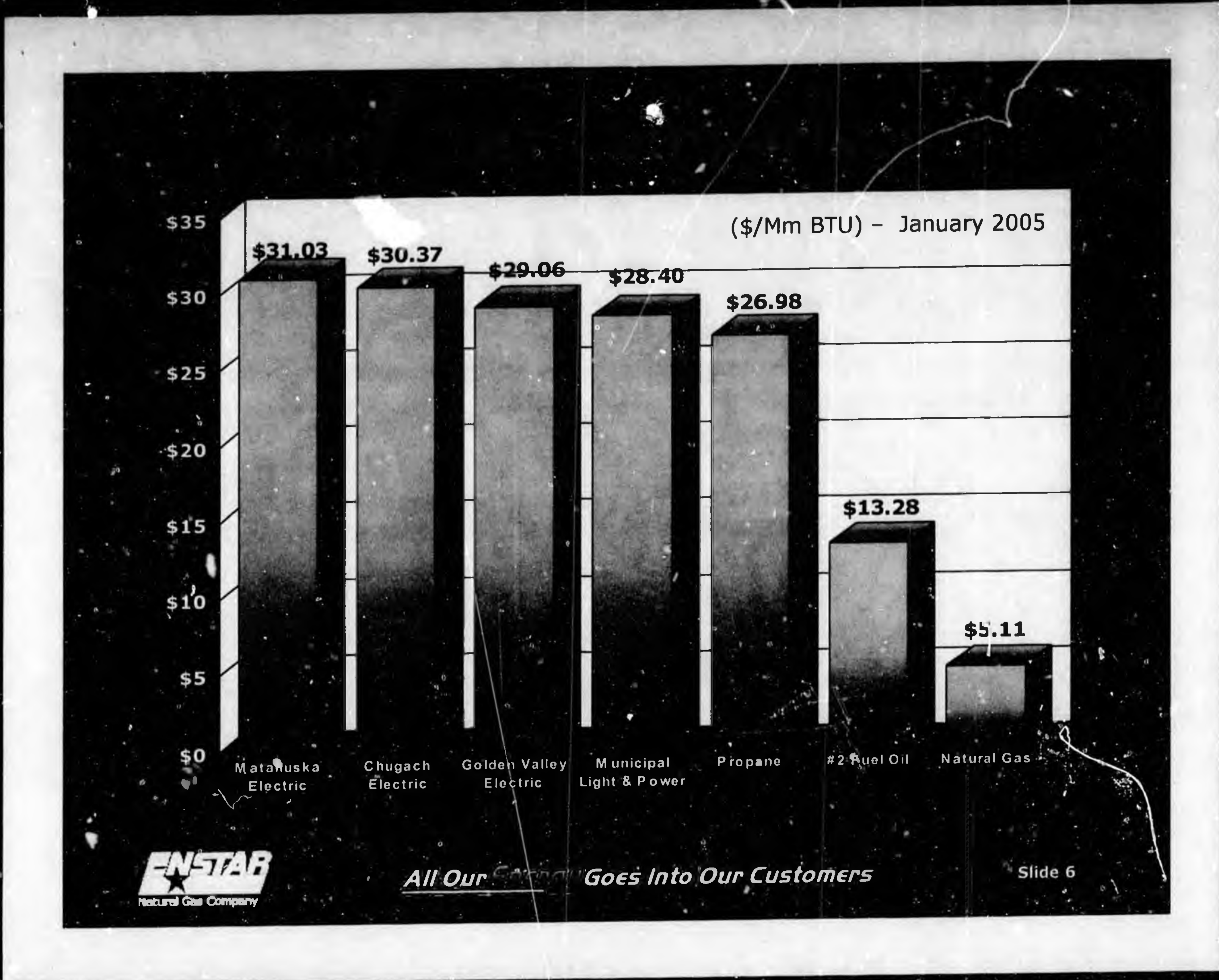
ENSTAR Natural Gas Company
Chugach Electric Assoc.
Matanuska Electric Assoc.
Golden Valley Electric
Municipal Light & Power
ENSTAR
Natural Gas Company
All Our
Goes Into Our Customers
Slide 4

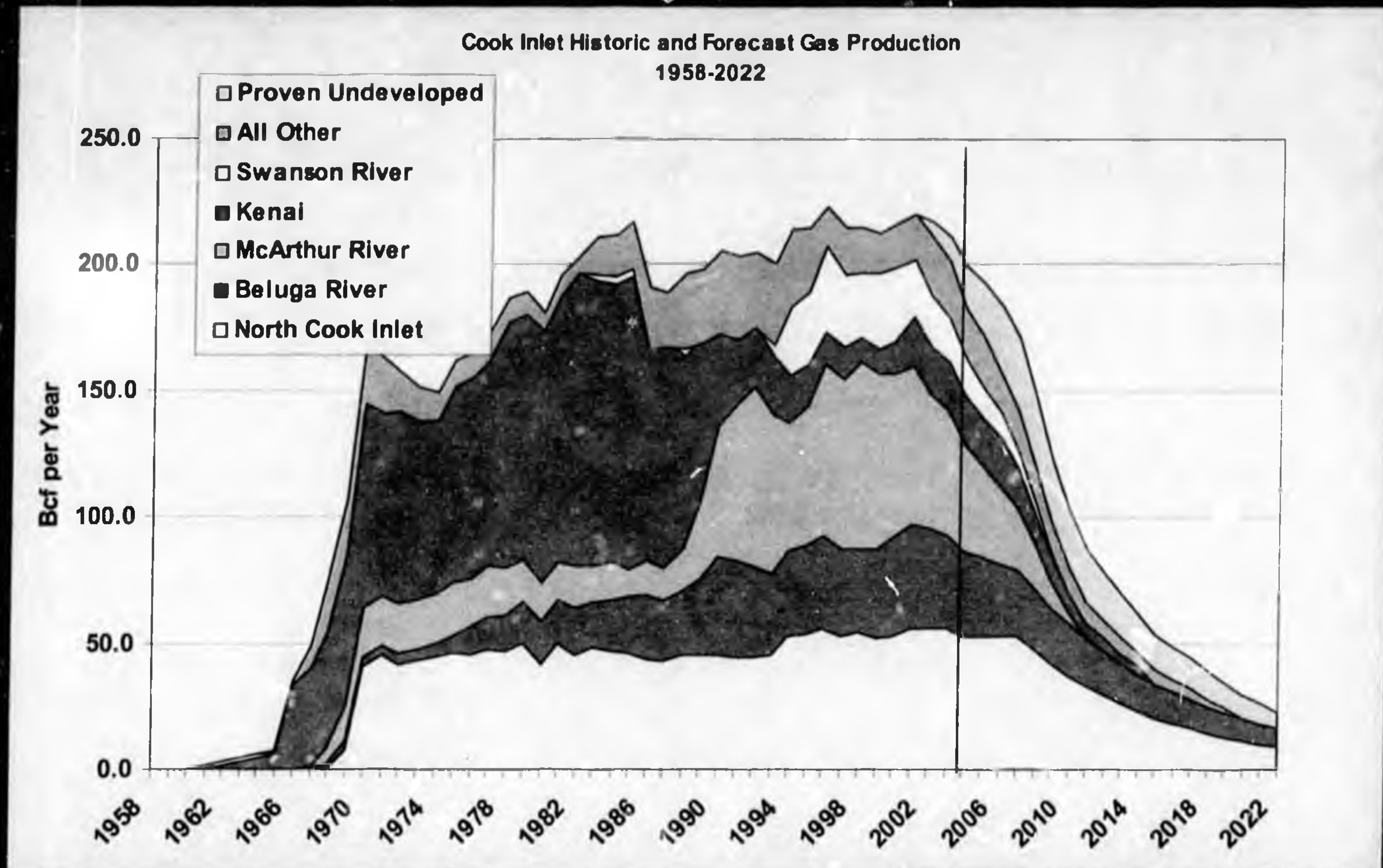


ENSTAR
Natural Gas Company

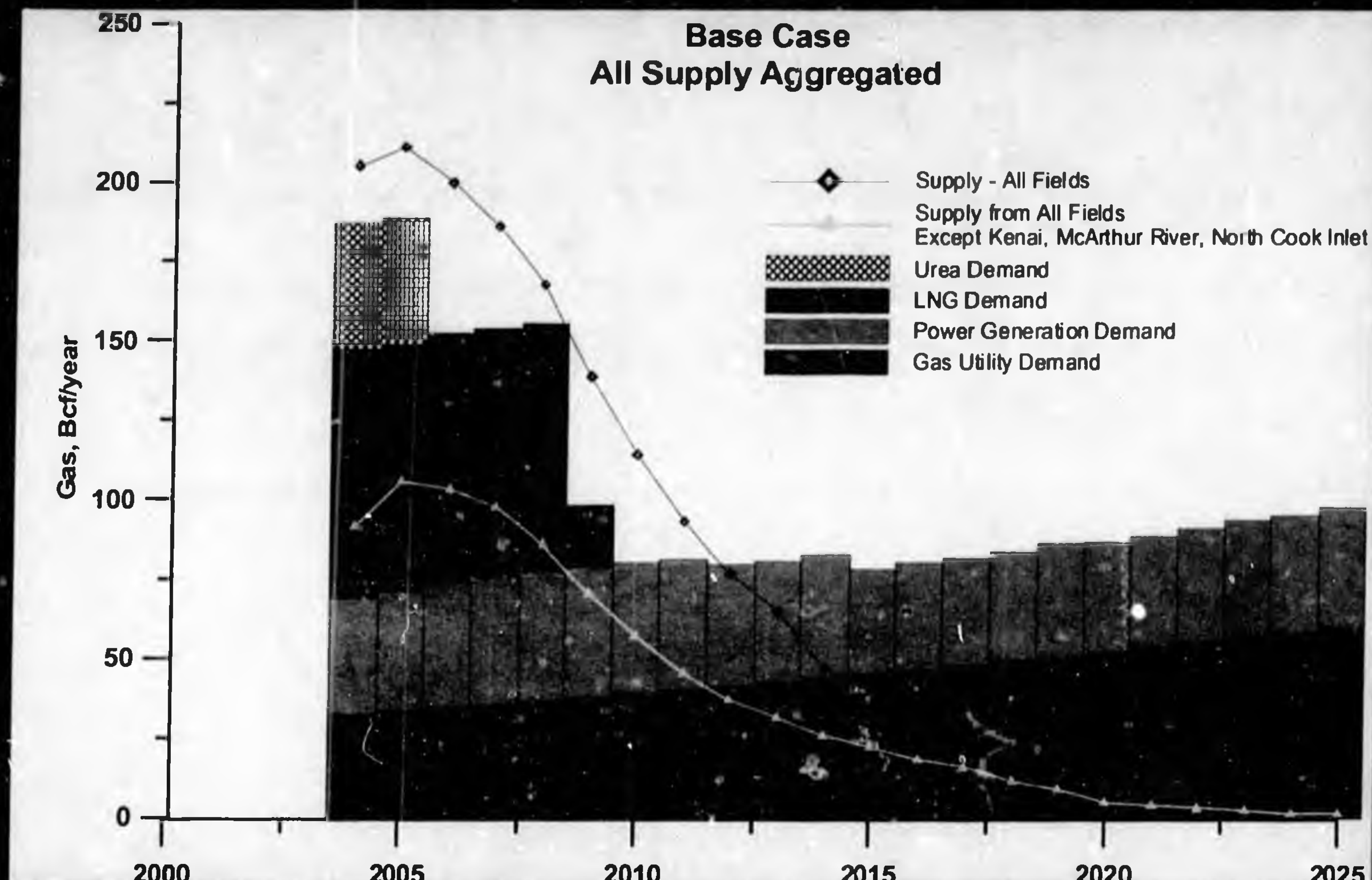
All Our Goes Into Our Customers



($/Mm BTU) - January 2005
$35
$30
$25
$20
$15
$10
$5
$0
$31.03
$30.37
$29.06
$28.40
$26.98
$13.28
$5.11
Matanuska Electric
Chugach Electric
Golden Valley Electric
Municipal Light & Power
Propane
#2 Fuel Oil
Natural Gas
ENSTAR
Natural Gas Company
All Our Goes Into Our Customers
Slide 6



ADNR Division of Oil and Gas. Alaska Oil & Gas Report. December 2003 has been updated and the new forecast is included.



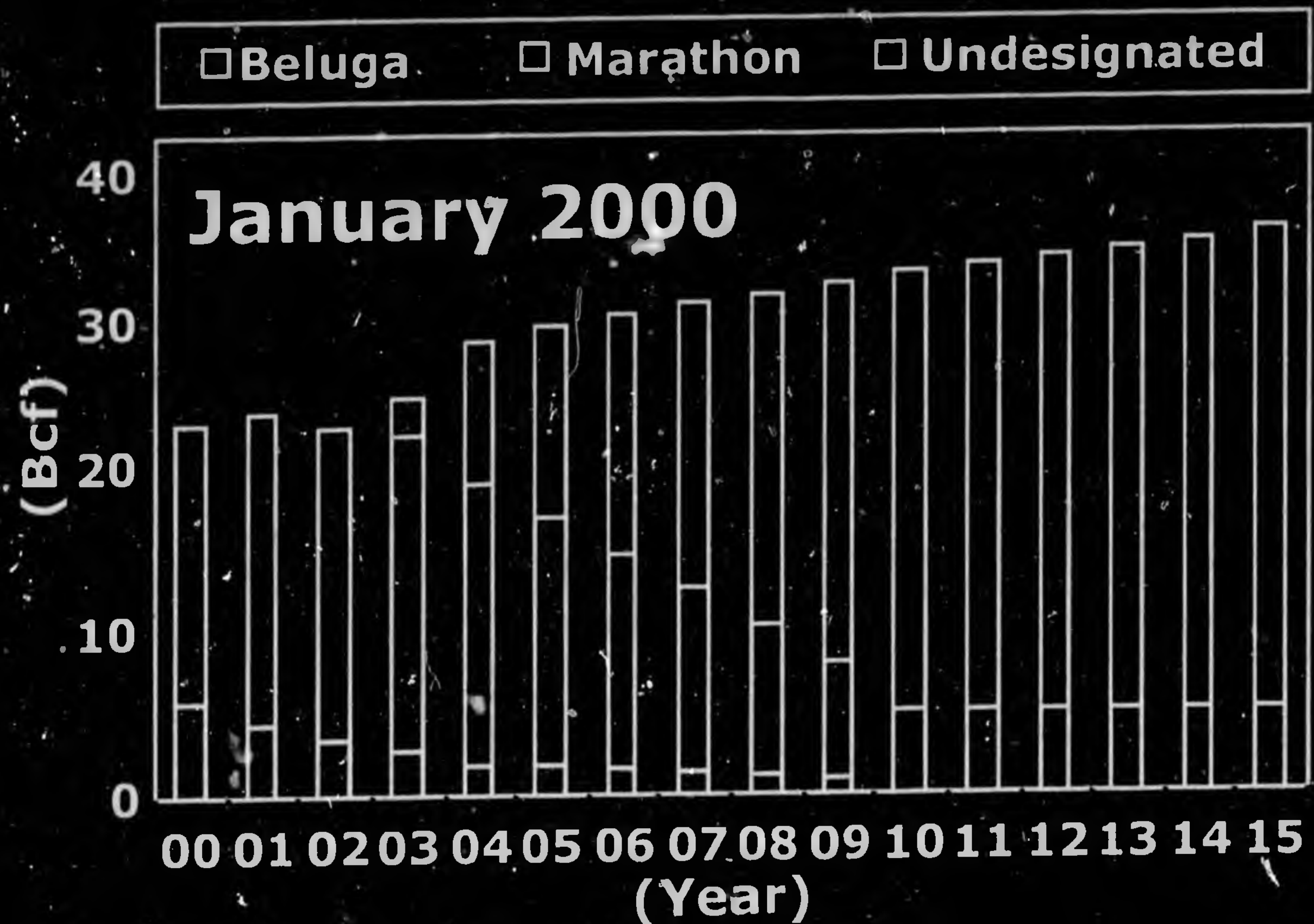
Department of Energy, June 2004

- Over 473,000 electricity consumers
  - 67% of electricity generated by natural gas
  - 15% hydropower
  - 13% diesel
  - 5% coal

- Over 318,000 natural gas consumers

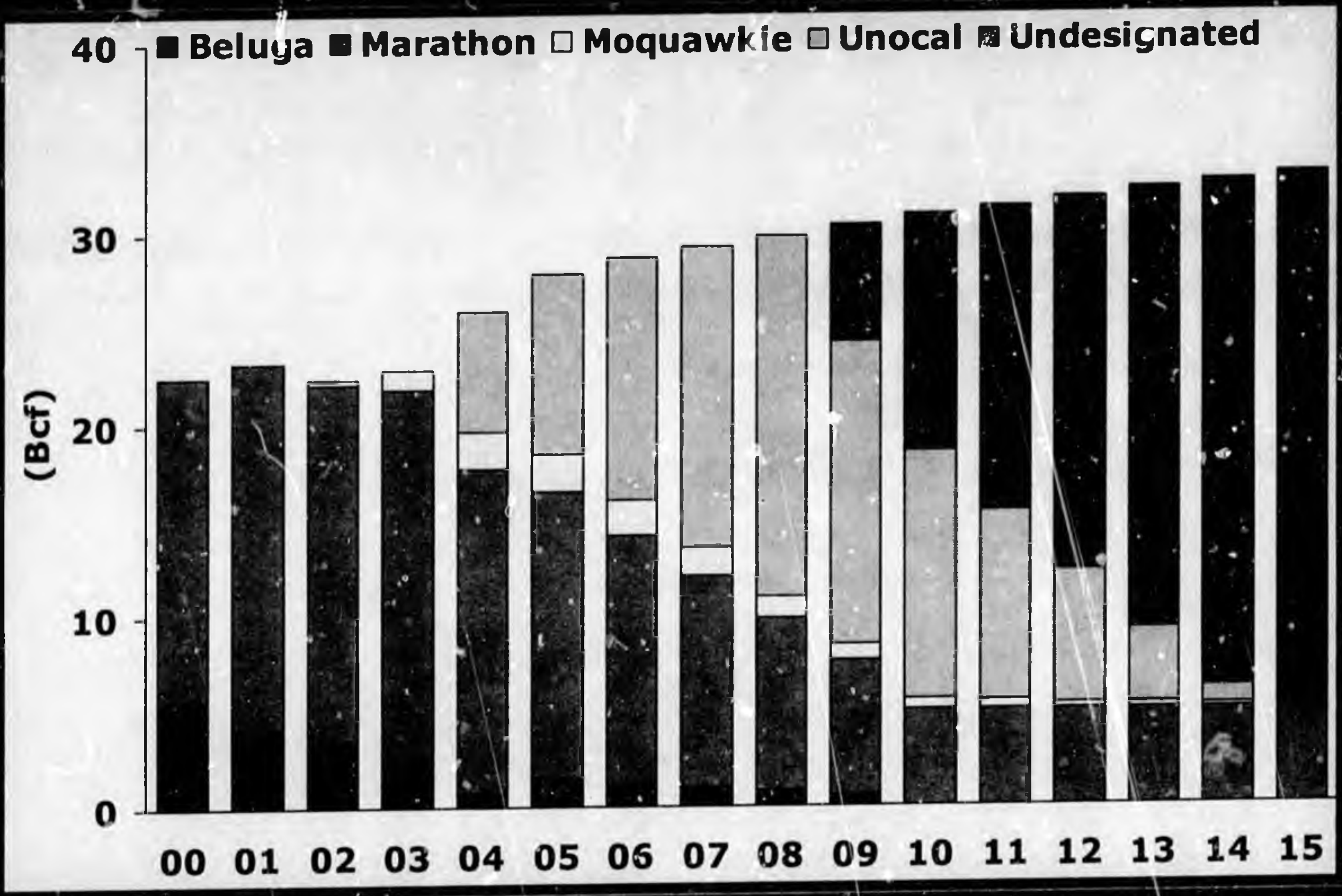
Weighted Average Cost per Mcf
$3.93

- Beluga (Oil price)
- Unocal (Henry Hub)
- Moquawkie (Inflation)
- Marathon (Oil)



ENSTAR Natural Gas Company

All Our [illegible] Goes Into Our Customers



Beluga
Marathon
Moquawkie
Unocal
Undesignated
(Bcf)
0
10
20
30
40
00 01 02 03 04 05 06 07 08 09 10 11 12 13 14 15

- Contract for additional supply
  - We have clearly moved from an "Excess Supply" market to a "Supply & Demand" market
- Identify and evaluate options to meet future natural gas demand
  - Achieved Federal support for an in-depth Department of Energy study of Cook Inlet supply and demand

- Determine future demand and supply of natural gas in South Central Alaska (Cook Inlet Basin) and **evaluate options** to meet the long-term demand

- Final Report released: July 2004
    - Full report can be found at: www.fe.doe.gov

1. Reserves Growth in Cook Inlet

2. New Exploration in Cook Inlet

3. North Slope Gas to Cook Inlet

- Exploration, reserves growth, or some combination can provide additional supply
- With assumed reserves growth (1.5 Tcf), there may be sufficient gas through 2025 for commercial and residential consumers and perhaps one industrial user
  - Reserves growth is estimated at $465 million

- The potential exists for an additional 13-17 Tcf of conventionally recoverable gas
- Investment required to explore and develop 50% of the estimated resources ***potentially*** available to be discovered could require investment of $5 to $6 billion, if the fields are onshore
  - If the fields are offshore, the investment needed would be higher

ENSTAR Natural Gas Company

All Our Energy Goes Into Our Customers

A North Slope gas pipeline has potential to moderate prices in the south central Alaska region

- Opportunity for a favorable price differential between Henry Hub and South Central Alaska

- Depending on North Slope to Chicago tariff charges, a spur could provide a $1.00/Mcf cost advantage over Henry Hub prices

- Opportunities:
  - Create value-added products in Alaska
  - Competitive industrial businesses

- Partnering with Department of Energy, ML & P & Chugach Electric and all concerned parties

- Analyzing the optimum mix of energy supply options to ensure continued economic growth in Alaska

- Measure possible benefits, costs and challenges of developing gas storage facilities in South Central Alaska

- Provide a detailed conceptual analysis to define the cost and benefits of a spur pipeline between South Central Alaska and Fairbanks

- Access to North Slope gas for all utilities is absolutely critical
  - Alaska could enjoy a 20-25% price advantage over the lower 48 with access to North Slope gas
  - Who will commit to delivering gas to Alaska consumers by 2012?
  - Who is ready, willing and able to begin a gas line to meet this schedule?
  - Who has economic interests most closely aligned with Alaska Consumers?

Now is the time to focus on responsible resource development with the appropriate urgency to ensure low cost energy for this and future generations