ALASKA NORTH SLOPE GAS COMMERCIALIZATION TEAM

REPORT TO THE GOVERNOR

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INTRODUCTION

In May 1997 the Alaska State Legislature, under the provisions of House Bill 250 (HB250), established a three-member North Slope Gas Commercialization Team consisting of the commissioners of Revenue, Natural Resources and the attorney general. The team was instructed ". . . to research and recommend changes to state law, and, in particular, to the state tax and royalty statutes on natural gas, to improve the economic feasibility and competitiveness of a North Slope gas project." HB 250 also requires the team to submit a report to the governor on or before January 12, 1998, summarizing its analysis.

The proposed project that currently appears most promising for commercializing the Alaska North Slope's vast gas resources would consist of a gas pipeline from the North Slope to Valdez, a liquefaction plant on the shores of Prince William Sound and a fleet of liquefied natural gas (LNG) tankers to carry the LNG to Asian customers. In competing for the limited space in the growing Asian LNG markets, the proposed Alaska project enjoys many important advantages. First, the project would diversify the LNG supply portfolio for the Asian markets by providing a very large supply source from a politically stable region and country. Second, the producibility of the necessary gas reserves has been well-established in comparison to the projected resources for other competing projects. But the proposed project does face some higher hurdles than its competitors in several areas. The proposed North Slope project requires a long pipeline with the attendant cost-overrun risk. The state, local and federal fiscal systems currently applicable to the proposed project – royalties and taxation – are not well-suited to the economics of the project nor well-suited to maximize the public benefit from the project. Further, gas projects similar to the proposed Alaska North Slope project usually require a long time period to return a profit to would-be investors, thus providing a competitive edge for proposed projects that can provide a guarantee of the long-term stability of the applicable fiscal system.

Finally, all of the projects competing for space in the Asian markets would require long-term supply contracts with Asian customers. The currently applicable state and federal commercial regulatory laws applicable to gas transportation systems such as the proposed Alaska project may require modification to ensure that the long-term supply contracts cannot be interrupted by other users of portions of the transportation system.

The North Slope Gas Commercialization Team focused its efforts on looking for ways, consistent with the public interest, to: (1) modify the applicable fiscal system; (2) provide some measure of fiscal certainty and stability; and (3) provide the protection needed for long-term gas supply contracts.

To accomplish its work, the North Slope Gas Commercialization Team established six technical working groups. The working groups are:

1. Fiscal Certainty
2. State and Local Fiscal Systems
3. Federal Action
4. Alaska Hire
5. Royalty-in-Kind/Royalty-In-Value
6. Commercial Regulation

Staff members from the following departments of state government contributed to the efforts of these working groups: Commerce and Economic Development, Labor, Law, Natural Resources and Revenue. Representatives of the following private companies participated in the meetings and analysis undertaken by each of the working groups: Arco Alaska, Inc., BP Exploration (Alaska) Inc., Exxon Company USA and Yukon Pacific Corporation. A representative from Phillips Petroleum Company also participated in the work of some of the groups.

The six technical teams worked through the period July to December 1997. Also, during this same time period, representatives of the North Slope Gas Commercialization Team and several of the technical working groups met with officials from communities along the probable gas pipeline corridor. In addition, the technical teams exchanged economic models and other pertinent information with Foothills Pipeline Company and several Japanese trading companies. The State and Local Fiscal working group and the Federal Action working group each receiving continuing assistance from Dr. Pedro van Meurs, author of the report, “Suggestions for New Terms for the Alaska North Slope LNG Project”, commissioned by the state in late 1996.

Finally, the North Slope Gas Commercialization Team held three public hearings – two of those in conjunction with the House Special Committee on Oil and Gas – to report on the work of the six technical working groups.

In addition to these in-state activities, meetings were held with representatives of the federal government in Washington, D.C. in late July. The purpose of these meetings was to discuss generally the potential benefits of the Alaska project to the United States and to enhance the state’s understanding on the willingness of the federal government to participate in creating a more competitive environment for developing Alaska’s North Slope gas reserves.

This report summarizes the conclusions of the state staff members participating in the six technical working teams. The North Slope Gas Commercialization Team endorses those conclusions. The private firms that participated in the work of the six technical working groups endorse some, but not all, of the conclusions. Detailed letters from Arco Alaska Inc., BP Exploration (Alaska), Inc. and Exxon Company USA commenting on the draft of this report are included as Appendices A, B and C to this report.

Within the next few weeks, the North Slope Gas Commercialization Team will forward for your consideration a legislative proposal. That proposal will be based upon the conclusions set forth in this report and will deal with the following issues:

1. Fiscal Certainty
2. State and Local Fiscal Systems
3. Alaska Hire
4. Royalty-in-Kind/Royalty-in-Value

While the mandates of HB 250 expire on January 12, we intend to continue working together as we have for the past six months to deal with the issues that will not be addressed in the legislative proposal we are preparing for your review. Those two areas are:

1. Federal Action
2. Commercial Regulation

Our summary of the analysis and conclusions of the six technical working groups follows.

PART I

FISCAL CERTAINTY

Fiscal certainty is an important element in risk reduction. The goal of the Fiscal Certainty working group was to analyze, develop and propose a statutory and contractual mechanism for providing fiscal certainty for an Alaska North Slope natural gas project.

I. CONSTITUTIONAL ISSUE RAISED BY THE USE OF A CONTRACT TO DEFINE TAX LIABILITY

The use of a contract to define tax liability raises the constitutional issue of whether a future legislature is prohibited under the U. S. Constitution from altering that liability. The relevant provision is Article I, Section 10 of the U.S. Constitution that says "No state shall . . . pass any . . . law impairing the obligation of contracts."

The Department of Law's position is that the state is constitutionally incapable, under Article IX, Section 1 of the Alaska Constitution, of entering into a contract that would prohibit a future legislature from exercising its power of taxation over a signer to the contract. Any contract purporting to set an individual's tax liability into the future would be subject to an implied term, if not an expressed one, reflecting this constitutional limitation.

Article I, Section 10 of the U.S. Constitution, the impairments of contracts clause, would not be violated by a subsequent legislative enactment changing a signer's tax obligation because no binding contractual obligation existed over the legislature's authority to pass new tax laws that apply to the signer. Therefore, the contract would not be impaired by the enactment of such a new law. The state may set by contract a person's tax liability, so long as it is understood that the contract does not limit the ability of a future legislature to revoke that contract and change that person's tax liability through the enactment of a general law. Viewed another way, Sections 1 and 4 of Article IX of the Alaska Constitution allow a contract to stand in the stead of a general law imposing a tax. This means that a future legislature may amend the tax liability imposed by the contract just as it may amend any general tax law.

There is a contrary interpretation of Article IX. Section 1 does not clearly state that the power of taxation may never be contracted away. Instead, it states "[t]his power shall not be suspended or contracted away, except as provided in this article." But nowhere else in Article IX is the suspension or contracting away of the taxing power explicitly discussed. The minutes of the Constitutional Convention reveal, however, that what the framers had in mind was the provision in Section 4 empowering the legislature to create tax exemptions by general law.

The framers' choice of language creates an ambiguity, if not an outright conflict, between Sections 1 and 4, because a general law tax exemption as a rule is not considered a "suspension" or a "contracting away" of the taxing power, but rather an exercise of it This ambiguity leaves open the argument that the framers' intent was to allow the legislature to authorize by general law the state to enter into contracts exempting persons from certain taxes and that such contracts would be binding on future legislatures--i.e., future legislatures could not impose new or different tax obligations on the signatories to the contracts without running afoul of the Impairment of Contracts Clause of the U.S. Constitution.

A. Implications of the Department of Law's Position

A contract with the state does not provide potential project sponsors with absolute certainty regarding the fiscal regime that a stranded gas project will be subject to over its life. This may discourage some potential investors, or perhaps increase the rate of return that the project needs to attract investors to compensate for the increased risk associated with the legislature's unilateral power to alter fiscal terms applicable to the project.

If the Department of Law is correct, the most that potential project sponsors can expect is a solemn pledge--a moral commitment--by the state that once it agrees to the fiscal terms, it will not change them.

B. Implications of the Contrary Interpretation

If the contrary interpretation is correct, greater certainty for project sponsors could be possible. It is unlikely, however, that the sort of absolute certainty that potential investors might desire is achievable within any reasonable time frame relevant to a decision to invest in the project given the Department of Law's interpretation and the unlikelihood of an advisory opinion on the issue from the Alaska Supreme Court.

II. CONCLUSION

The fact that the contrary interpretation is not frivolous, and could prevail in future litigation, suggests that the administration should not endeavor to reflect the tax regime applicable to a gas project in a contract, and the legislature should not in any way ratify such a contract unless both are convinced that the contract's terms are in the state's best interests and both are willing to abide by those terms throughout the stipulated life of the contract.

PART II

FISCAL SYSTEM

The goal of the Fiscal System working group was to recommend changes to the state's current fiscal system to encourage sponsors to invest in the project and at the same time make it possible for the state to obtain the highest share of the economic rent. [1]

I. CURRENT FISCAL SYSTEM

The state's fiscal system consists of four main elements:

- Ad valorem property tax
- Corporate income tax
- Production (severance) tax
- Royalty

A. Ad Valorem Property Tax

The property tax is based on 20 mills of assessed value. Value can be determined on either a cost or income approach. Insofar as assessment reflects some judgment the property tax administration on oil facilities has not been without dispute.

Much of the property tax is ultimately collected by the local jurisdictions.[2] It has been a significant source of funds for the communities bearing the social costs associated with oil development. In addition, although the need for social services has not declined, the property's value is a declining asset and the corresponding decline in property tax revenue has been a problem for the communities.

As structured, however, the property tax creates a significant problem for investors. The tax is assessed as soon as construction commences. This can be years before revenue is realized. This is called "front-end loading." On a present value basis this creates a tremendous drag on investors' rate of return, especially given the long construction period and ramp-up period of this project.

In addition, since the tax is assessed based on cost, it compounds the downside risks to the project at low prices. The tax is insensitive to gas prices. At low gas prices this sensitivity could make the tax an unacceptable burden. Moreover, since it is based on cost it exacerbates cost overrun risk. Not only would the cost be higher, but the tax would be higher as well.

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[1] There would be other benefits to the state besides the direct fiscal ones. Most notably these would include gas to local communities and economic benefits during construction.
[2] The state levies the tax at 20 mills and then credits an amount equal to the local mill rate.

Where taxes are fixed and unrelated to profits they are “regressive.” As shown below, other elements of the state’s fiscal system in addition to the property tax are regressive. With regressive systems the state takes higher shares of the profit when profits are low, and lower shares when profits are high. Again, this presents additional risk to investors when prices are low.

B. State Corporate Income Tax

The state corporate income tax, like that of most other states, is based on apportioning either domestic or worldwide income to establish the "deemed" Alaska income subject to the state nominal tax rate of 9.4%. The apportionment fraction is the average amount of the taxpayer’s property, hydrocarbon extraction and sales in Alaska relative to that in the rest of the world.

Apportionment introduces regressive elements in the tax burden for both newcomers and existing producers. Any new investment will increase the property factor in the tax equation, beginning when it is placed in service. Given the expected long ramp-up of the project, this could increase the tax years before any material net income is earned. In addition, for newcomers, any such investment will establish nexus with the state, automatically subjecting their worldwide income to the Alaska tax apportionment formula.

The state’s current corporate income tax structure also makes it difficult to project accurately the economics of a proposed project. To assess the effect of the tax on the economics of the project, it is necessary to anticipate what the investor’s worldwide income, and worldwide property, extraction and sales will be throughout the life of the project. This is obviously impossible.

C. Production (Severance) Tax

The gas severance tax is 10 percent of the wellhead value. The point of assessment for this tax is upstream of any gas processing facilities; therefore the wellhead value is net of a processing fee. The tax rate is subject to an economic limit factor (ELF), a fraction between zero and one, which gives each well 3,000 mcf per day tax-free.

There is a minimum floor in the gas severance tax of 6.4 cents per mcf, subject to the ELF; this element of the severance tax is regressive.

Oil is also subject to its own ELF.[3] When oil and gas are produced from the same well, which will be the case for Prudhoe Bay gas, the tax-free treatment afforded by the ELF is prorated between oil and gas based on relative volumes produced. Thus when wells that previously produced only oil start to produce gas as well, there will be fewer tax-free

[3] Oil gets 300 barrels per well per day tax free, subject to field size. Fields producing over 150,000 barrels per day get progressively less than 300 barrels, while fields producing less than 150,000 barrels per day get progressively more than 300 barrels.

barrels of oil from each well. Consequently, oil taxes will increase. Clearly, the producers will treat this as an additional cost of the project in assessing the project's feasibility.

D. Royalty

The royalty represents the state ownership interest of the resource. At Prudhoe Bay it is 12.5 percent of the wellhead value. Under the severance tax statutes and the applicable royalty provisions, royalties have virtually the same point of valuation as the severance tax.

II. MODEL OF THE PROJECT AND FISCAL SYSTEM

The working group has developed an economic/financial cash flow model of the project and the current fiscal system. The working group has constructed the model so that it can be used to analyze other potential fiscal systems. In developing the model the working group solicited and received assistance from the various interested parties.[4] The model is public and is available to anyone wishing to do their own analysis.

The model represents the Prudhoe Bay field. At this point too little is known regarding other gas deposits and their potential development to meaningfully model them. Gas production from other deposits would ameliorate some of the oil losses from Prudhoe Bay associated with gas development there (see below).

A. Reference Case

1. Price

The reference case uses a delivered LNG price of $3.50/mmbtu in 1997 dollars as a market price. We believe this price reflects the long-term established trend. In the reference case model this price remains constant in real terms. To value oil losses, and to keep oil and gas energy prices consistent, the projected ANS market price of crude oil is linked to the gas price using the Japanese crude "cocktail" (JCC) relationship to LNG prices. The JCC is the mix of Japanese import crudes used to price LNG in the contracts under which LNG is delivered to Japan. A representative LNG price formula links the JCC to LNG prices.

This price assumption when combined with the other reference case assumptions results in a netback value for gas at the point of production on the North Slope of $0.87/mcf in 2005, or $0.69/mcf in 1997 dollars.[5]

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[4] The state's model was put together after discussion with the primary Prudhoe Bay gas owners (Arco, Exxon, and BPX), Yukon Pacific, Phillips, Foothills Pipeline, and the pipeline communities.
[5] Based on a levelized tariff which yields a 10% nominal return.

2. Cost

Development costs are assumed to be $12 billion in 1997 dollars.

3. Operating Cost

Annual operating costs are estimated base on a percentage of capital costs in 1997 dollars:

Conditioning plant	5.4%
Pipe	2.2%
Liquefaction facility	5.5%
Ships	3.5%

4. Volume

Sales volume is 13.67 mmta for three trains. This equals 1.65 bcf/d to market, and 1.9 bcf/d to the conditioning plant.

5. Ramp-Up Schedule

The full production plateau is reached in six years. Reaching this plateau requires the placing of large volumes of gas in a relatively limited market. The economic feasibility of the project will be quite sensitive to the ramp-up. Ultimately the duration will depend on marketing.

6. Timing

The reference case is based on start-up of sales in 2005 preceded by a five-year construction period. The amount of oil production lost as a consequence of the project will be a function of the start-up date of the project. Voiding the oil reservoir of gas depletes pressure, an important recovery mechanism. Oil losses would increase gradually over time but producing the gas later would reduce the overall oil loss by allowing producers to keep using the gas to force more oil out of the ground. We estimate that a 2005 start-up would result in reduced recovery of 318 million barrels of oil. A 2010 date reduces this to 173 million barrels.

The lost oil analysis also includes changes to the TAPS tariff from reduced oil flow.

7. Inflation

We assume 3% inflation for both costs and prices.

8. State discount rate

We use a state discount rate of 7% to evaluate the present value of income to the state.

9. Project structure

Project structure determines how parties share the price and cost risk. In the reference case we assume an integrated structure, where the producers control the entire project from the wellhead to the market, assuming both price and cost risk. Below this project structure is referred to as project structure No. 1.

10. Federal and state tax depreciation

The depreciation schedules provided under the current laws were employed. Depending on the class of assets this ranges from 8 to 16 years for federal and 12 to 18 years for state.

11. Gas loss in transit

Around 13% of the gas is used up in transit in the forms of fuel use, evaporation, and other losses. The gas remaining after these losses, expressed as a percentage of gas entering the conditioning plant (excluding CO2), is:

Pipeline	96.76%
Liquefaction facility	95.12%
Ships	88.88%
Market	86.73%

12. BTU enrichment

Gas is sold by the BTU. Prudhoe Bay gas has access to natural gas liquids, which can enrich the BTU content of the gas and increase its value on a volumetric (mcf) basis. We used a 15% enrichment, where a mcf of gas equals 1,150 BTUs.

13. Property Tax

Property tax in the model is assessed based on historic cost. This is equivalent to a replacement cost approach if technological improvements are assumed to offset cost inflation.

14. Weighted Average Cost of Capital (WACC) (for netback methodology)

In computing a cost allowance to derive a netback value we assume the sponsors are allowed to earn a rate of return on cash flow equal to our estimate of the sponsor's WACC. We assume 10% based on expected percentages of debt and equity in the capital structure, interest rate, and returns on equity.

14. Abandonment Cost

Abandonment costs were estimated to be $1 billion in 1997 dollars incurred in 2034.

B. Scenarios around Reference Case for Sensitivities

1. Price

Market prices ranging from $2 - $8/mmbtu in 1997 dollars were modeled at the following levels: $2.00, $2.50, $3.00, $3.25, $3.50, $3.75, $4.00, $4.25, $4.50, $5.00, $5.50, $6.00, $7.00, and $8.00.

2. Cost

Total project costs ranging from $10 billion - $15 billion in 1997 dollars were modeled at billion-dollar intervals.

Note that prior to starting the project, the market price for LNG and the project costs will be key unknown elements and therefore represent the greatest risks.

3. Volume

We modeled the addition of a fourth LNG train. In addition to an additional liquefaction facility and ships, there are additional downstream costs for a larger conditioning plant and pipeline compressors. The total incremental cost was about $3 billion.

4. Project Structure

Two additional project structures were analyzed. In the first the producers would assume the price risk and a third party assumes the cost risk. The gas producers sell the gas and pay third-party downstream investors fixed tariffs for the pipeline, liquefaction, and shipping. The producers pay a third party a fixed amount for the downstream costs ($12 billion) regardless of actual cost. Because of the cost risk, we have assumed that the third party earns a higher rate of return (12%) on the contracted cost. This project structure is referred to below as project structure No.2.

In the second additional project structure, a third party would assume both the price and cost risk. This was modeled by having a third party purchase the gas from the producers at the lease boundary. Prices of 50 cents and $1.50/mcf were analyzed. These are referred to below as project structures No. 3A and No. 3B.

It should be noted that the actual project structure may be more complicated than these examples and may change during the life of the project.

5. Ramp-Up Schedule

A four-year ramp-up schedule was examined. Note that this schedule increases the projected oil losses somewhat.

6. Timing

A 2010 start-up was examined. This later start-up reduces the projected oil losses. (See above.)

7. Weighted Average Cost of Capital (WACC)

Rates of 8% and 12% were examined.

8. Federal Depreciation

A five-year accelerated schedule was examined. This is more in line with competing jurisdictions.

9. Federal Investment Tax Credit

A 5% federal investment tax credit was examined.

10. Other

In order to examine the net present value of revenue streams, and relative shares of discounted economic rent, discount rates of 7%, 10%, and 15% were run for both the investors and the state.

In the reference case we examined the economics as if there was no leverage, or debt in the project. In that way the results reflect the economics of the project itself without the effects of the financing arrangements. The results reflect a return to both the debt and the equity with the WACC as a minimum hurdle rate. Any competing projects yielding higher returns could increase the minimum hurdle.

As a sensitivity we looked at a leveraged project, with debt. Since the cost of debt is explicit, the result represents a return to equity with the required return on equity as the minimum hurdle rate.

III. MODEL RESULTS FOR CURRENT FISCAL SYSTEM

A. Current Fiscal System with Sensitivities

The current fiscal system was modeled under the base reference case and selected sensitivities described above. The return to the investors (nominal) from each case is as follows.[6] For a qualitative general frame of reference, Dr. Pedro van Meurs, international oil and gas fiscal consultant to the state, estimates that returns on total capital in excess of roughly 12%[7] at a $3.50/mmbtu market price are necessary to make the project competitive:

- Base reference	10.76%
- Five-year accelerated federal depreciation	11.24%
- 5% federal investment tax credit	11.00%
- Four-year ramp-up	11.19%
- Fourth train (return on whole project)	10.96%
- Project structure No. 2	11.00%
- Project structure No. 3A	10.87%
- Project structure No. 3B	10.23%
- 12% WACC on downstream	11.00%
- 8% WACC on downstream	10.38%
- Leverage	15.02%[8]

The following shows the returns from the base reference case with a $12 billion cost at various gas prices. Note that higher rates of return are required at higher prices to be competitive:

- $2.00	5.18%
- $2.50	7.47%
- $3.00	9.36%
- $3.25	10.12%
- $3.50	10.76%
- $3.75	11.36%
- $4.00	11.93%
- $4.25	12.48%

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[6] All rates of return, discount rates and assumed costs of capital referenced thereafter are nominal. They reflect returns on development and exclude expenditures on engineering prior to final design and permitting costs.

[7] This could change in the future depending on market conditions.

[8] Since the return on the leverage case is to equity only, the hurdle rate is elevated above that in the unleveraged case where the return is to both debt and equity.

- $4.50	13.01%
- $5.00	14.02%
- $5.50	14.98%
- $6.00	15.89%
- $7.00	17.60%
- $8.00	19.17%

The following shows the returns from the base reference case with a $3.50 per mmbtu price at various project costs:

- $10 B	12.41%
- $11 B	11.53%
- $12 B	10.76%
- $13 B	10.06%
- $14 B	9.36%
- $15 B	8.65%

The following shows the state share of the discounted (7%) economic rent (pre-tax profit) at the various gas prices and a $12 billion cost:

- $2.00	263%
- $2.50	36%
- $3.00	19%
- $3.25	17%
- $3.50	18%
- $3.75	18%
- $4.00	19%
- $4.25	19%
- $4.50	19%
- $5.00	20%
- $5.50	20%
- $6.00	21%
- $7.00	21%
- $8.00	21%

This table reflects the regressivity of the state's current fiscal system. Two major elements of the state's fiscal system are the major contributors to this regressivity. First, the property tax, which is determined by the project cost and remains fixed regardless of LNG price and project profitability, gives the state an extraordinary share (proportion) of the rent at low prices. This feature of the current system creates price risk for the investor. Second, the state takes virtually the same share of the rent at a $8 price that it takes at a $3 price. Under the principles employed for most of the fiscal systems applicable to LNG projects the state could be taking a higher share under favorable economic conditions.

B. Derivatives to Current System

1. Modifications to Property Tax

The most problematic element in the current fiscal system that makes it so front-end loaded and regressive is the property tax. However, insofar as the property tax is an important revenue source to local communities, we examined whether it was possible to modify the property tax in some manner to reduce its damaging effects on the proposed project's economics.

The following modifications were examined:

a. Five-year property tax holiday.
b. Ten-year property tax holiday.
c. Deferral of property tax during construction and ramp-up (interest) free) with deferred amounts paid on a levelized basis over 25 years.
d. Property tax only on a liquefaction facility.
e. Remove state share of property tax.
f. $50 million annual property tax.
g. Property tax reduced by half during construction and ramp-up.

While these modifications are aimed at either reducing the property tax or tempering the front-end load of that tax, they each result in a regressive tax; they result in tax amounts that are insensitive to profits, which creates price risk.

The following shows the rate of return to the investors and state share of the discounted economic rent for each option at $2.50 and $3.50 per mmbtu gas:

	$2.50	State Share of Rent	$3.50	State Share of Rent
Base reference	7.47%	36%	10.76%	18%
a.	7.62%	31%	10.90%	16%
b.	7.90%	20%	11.14%	13%
c.	7.71%	27%	11.00%	15%
d.	7.99%	16%	11.17%	12%
e.	7.69%	28%	10.93%	15%
f.	7.91%	19%	11.10%	13%
g.	7.68%	28%	10.95%	15%

2. Other Modifications

We also examined modifying other aspects of the current fiscal system referenced above that we believe are suboptimal, as well as other possibilities within the current state tax code. These include:

a. No minimum severance tax
b. Royalty relief (5% rate) for the first 10 years
c. Remove ELF effect that increases oil severance tax when gas gets produced
d. State 5% investment tax credit
e. Not subject gas activity to apportionment
f. Not subject gas activity to state corporate income tax

The returns and state share are as follows:

	$2.50	State Share of Rent	$3.50	State Share of Rent
Base reference	7.47%	36%	10.76%	18%
a.	7.57%	32%	10.76%	18%
b.	7.47%	37%	10.82%	17%
c.	7.50%	35%	10.82%	17%
d.	7.70%	27%	10.93%	16%
e.	7.61%	31%	10.84%	16%
f.	7.62%	30%	10.84%	16%

3. Combinations of Modifications

We also examined four different combinations of the above options:

a. 1(b) and 2(a,b,c,d,and e)
b. 1(c and f) and 2(a,b,c,d, and e)
c. 1(b and f[after holiday]) and 2(d)
d. 1(b and f[after holiday]) and 2(a,b,c,d, and e)

where 1 is the property tax modifications above and 2 is the other modifications above

The returns and state share are as follows:

	$2.50	State Share of Rent	$3.50	State Share of Rent
Base reference	7.47%	36%	10.76%	18%
a.	8.41%	-1%	11.60%	7%
b.	8.17%	5%	11.38%	9%
c.	8.34%	3%	11.45%	9%
d.	8.62%	-9%	11.69%	5%

As long as there is either a property tax based on cost, or a fixed property tax, the combinations will still produce a regressive system. The property tax modifications coupled with the other modifications do temper the regressiveness.

The following is the state's share of the rent at high prices for the scenarios above:

	$4	$5	$6	$7	$8
Base reference	19%	20%	21%	21%	21%
a.	10%	13%	14%	19%	21%
b.	11%	15%	17%	19%	21%
c.	12%	16%	17%	18%	20%
d.	8%	11%	13%	14%	15%

These combination systems are progressive in direction. Note, though, that the most any one system increases the state share between a $3.50 price and a $8 price, a very large difference, is 14 percentage points. At high prices none of the combination cases raises the state's share of the rent above the current system. It is possible that the state should be getting a higher share at higher prices.

Results of all options at all sensitivities, prices, and costs are available from the Department of Revenue. However, we caution that coupling relatively improbable events with other relatively improbable events results in outcomes that are vastly more improbable.

IV. FISCAL PRINCIPLES

The current fiscal system for gas is modeled after that for oil. The economics of these two resources are vastly different. Where the current system may be appropriate for oil, it may not be appropriate for gas, particularly for LNG. We have attempted to derive the most appropriate fiscal system for this resource. Accordingly we have developed a set of principles that we believe would be the most appropriate for developing a fiscal system for Alaska's North Slope gas resource.

The principles are as follows:

1. The fiscal system, in conjunction with other factors, such as cost reduction, risk reduction, and marketing, should make the project competitive compared to viable competing projects aimed at supplying the same market. This would be achieved by enhancing returns to investors and reducing risk.

2. The fiscal system should accommodate the interests of the state and the sponsors under a wide range of possible market and economic conditions. It should also recognize the evolving planning arrangements for the project. This is discussed further in Section VI below.

3. The state share of the economic rent should be progressive; overall state take, on a percentage basis, should not increase with decreasing profitability, and should not decrease with increasing profitability. This would reduce both low price risk and cost overrun risk to the investors. If the tax rates are not excessive, the system would also be efficient; because it would provide a maximum incentive to the investors to reduce their costs.

4. The state take should be back-end loaded in relation to time; overall state take during the early years should be less than during the later years. This provides sponsors an opportunity to recover their investment earlier, which reduces risk. As long as the state has a lower discount rate than investors, which appears to be the case,[9] back-end loading of fiscal terms benefits investors more than it costs the state. Also, it should give the state and the project sponsors a solid argument for requesting corresponding change in federal taxes such as accelerated depreciation, another mechanism for back-end loading the tax burden on the project. Finally, back-end loading provides the state government with a smoother transition from an oil-based revenue to a gas-based revenue.

Note, however, that back-end loading taken to excess could cause a misalignment of interests between the state and sponsors.

5. The fiscal system should recognize the risks borne by the project sponsors and allow them to retain upside potential commensurate with the risks they are undertaking.

6. The fiscal system should provide a significant state take under favorable price and cost conditions. This take may be higher than what it would be under the current system.

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[9] Investors are competing with other entities for shareholder equity. The state is providing public services. Thus the investors' and the state's opportunity costs and discount rates should be different.

7. The fiscal system should clearly define the basis for calculation of the state take.

8. The fiscal system should incorporate valuation, and if appropriate, netback methodologies, which reflect or closely approximate actual revenues, costs and tariffs. Where costs and/or tariffs must be imputed, they should reflect the economic realities facing investors. Where possible, administrative efficiency should be promoted through the use of agreed formulae in determining the basis for payments to the state.

V. FISCAL ALTERNATIVES

Economists today are nearly unanimous in their belief that taxes based on profits are the most efficient. Taxes on profits minimize incentives to engage in "tax planning" behavior that reduces net social value.[10] In establishing a tax system for North Slope gas the two main issues the state must address are the locus of the profit and the derivation of the profit.

The tax base could be subject to a tax table that could be both progressive and back-end loaded: progressive with escalating rates as the tax base increases, and back-end loaded with rates escalating over time.

An example of such a progressive, back-end-loaded system is reflected in the following table:

Wellhead (Netback) Price (Taxable profit) ($1997)	Under $0.50	$0.50 - $1.00	$1.00 - $1.50	Over $1.50
2000	0	0	0	0
2001	0	0	0	0
2002	0	0	0	0
2003	0	0	0	0
2004	0	0	0	0
2005	12.50%	20.00%	30.00%	50.00%
2006	12.50%	20.00%	30.00%	50.00%
2007	12.50%	20.00%	30.00%	50.00%
2008	12.50%	20.00%	30.00%	50.00%
2009	12.50%	20.00%	30.00%	50.00%
2010	12.50%	20.00%	30.00%	50.00%
2011	12.50%	20.00%	30.00%	50.00%
2012	12.50%	20.00%	30.00%	50.00%

[10] Net social value is the total net resources available to the economy as a whole without regard to the distribution of those resources.

2013	12.50%	20.00%	30.00%	50.00%
2014	12.50%	20.00%	30.00%	50.00%
2015	12.50%	20.00%	40.00%	50.00%
2016	12.50%	20.00%	40.00%	50.00%
2017	12.50%	20.00%	40.00%	50.00%
2018	12.50%	20.00%	40.00%	50.00%
2019	12.50%	20.00%	40.00%	50.00%
2020	20.00%	30.00%	40.00%	50.00%
2021	20.00%	30.00%	40.00%	50.00%
2022	20.00%	30.00%	40.00%	50.00%
2023	20.00%	30.00%	40.00%	50.00%
2024	20.00%	30.00%	40.00%	50.00%
2025	20.00%	30.00%	40.00%	50.00%
2026	20.00%	30.00%	40.00%	50.00%
2027	20.00%	30.00%	40.00%	50.00%
2028	20.00%	30.00%	40.00%	50.00%
2029	20.00%	30.00%	40.00%	50.00%
2030	20.00%	40.00%	50.00%	50.00%
2031	20.00%	40.00%	50.00%	50.00%
2032	20.00%	40.00%	50.00%	50.00%
2033	20.00%	40.00%	50.00%	50.00%
2034	20.00%	40.00%	50.00%	50.00%

The tax rate is subject to the year and the wellhead value. The tax rate for any wellhead value applies to the incremental amount over the prior value. For example, in 2015, if the wellhead value were $1.19 in 1997 dollars, the tax rate would be:

- 12.5% for the first $0.50, plus
- 20% for the amount between $0.50 and $1.00, plus
- 40% for the amount between $1.00 and $1.19

A. Locus of Profit

Taxable profit can be centered either upstream (prior to gas leaving the lease) or downstream (after gas leaves the lease). Depending on the allocation of risks, taxable profit may also be spread through the segments.

1. Upstream Profit

A fiscal system that attributed the economic rent as if it were earned upstream would be similar to the current fiscal system applicable to North Slope oil production. The market price in the destination markets less all downstream costs (in this case conditioning, pipeline, liquefaction, and marine transportation) yields a netback, or wellhead value, which, in this case, would be virtually synonymous with profit. In the case of gas from the main Prudhoe Bay reservoir, costs upstream of the lease boundary may not be significant. If so, all value from the project could be attributed to the upstream for state tax purposes.

Since the tax value of the entire project would be attributed to the upstream, the producers may be responsible for the tax.

2. Downstream In-Lieu-Of Property Tax

A fiscal system that attributed the economic rent as if it were earned downstream would put the locus of the payment to the state, and define profit, downstream. Using this approach would essentially reshape the property tax to make it back-end loaded and progressive. This would focus fiscal modifications on new investment, rather than modifying upstream provisions to encourage downstream investments. If the fiscal changes were focused on the downstream, upstream taxes and royalties would probably be unchanged.

The downstream tax base would be the market price less both a cost allowance (without profit) and the wellhead value. Thus only the value added, or returns earned by the downstream, would be taxed. Again, such a system could be reflected in a lookup table like the one described above.

Modifying the fiscal system in this manner could create the possibility of two tax loci, which might create an incentive to shift value toward the lower-valued locus. If you wanted to eliminate this possibility, a new downstream fiscal system should be constructed to replace all taxes in which case the tax base would be the same as in the upstream structure, with the downstream responsible for payment.

B. Derivation of Profit

Profit is generally revenue less cost. Or more specifically, the tax base is the market price less a cost allowance. The cost allowance consists of eight basic elements:

- Recovery of capital (depreciation)
- Return on capital (profit)[11]
- Operation and maintenance
- Downstream pre-income taxes (i.e., property tax)
- Debt (to the extent it is not already covered by depreciation allowance)
- Interest on debt (to the extent it is not already covered by the return on capital)
- State corporate income tax
- Federal corporate income tax

[11] The rate of profit would be subject to negotiation.

We analyzed two different approaches to calculate the annual profits of the proposed project: a levelized cost approach and a cash flow approach.

1. Levelized Costs

In a levelized cost approach the total costs to the project are spread evenly to each of the units produced as a per-unit allowance. Using this approach accurately allocates the economic and book (accounting) costs. In a project such as this, with high up-front costs coupled with a relatively slow ramp-up of revenues, levelization prevents the early tax base from being negative. Since the allowance is based upon the expected lifetime costs, it can be complicated (but not impossible) to accommodate unexpected additional costs incurred after the start of the project.

Set formulae would be required to establish allowances. It is possible that a one-time audit with periodic updates could establish the capital cost allowances. More frequent audits on operating expenses would probably be required. Where both the tax incidence and the sales transactions occur at the wellhead, these audits might be unnecessary if the sales price resulted from truly a bona fide arms-length transaction.

2. Cash Flow

In a cash flow approach the annual costs are deducted as incurred. When costs exceed revenues, the costs in excess of the revenues are carried forward. While using this approach for the proposed North Slope gas project would readily accommodate any unexpected costs as they were incurred, it would most likely result in no tax base for several years. It also would require a more intense annual audit effort. It is possible to create a minimum positive tax base for every year by capping annual cost deductions as a percentage of revenues. This, however, would make the system regressive.

Since this system allows for cost recovery before taxation occurs it is inherently back-end loaded.

C. Results of Modeling

Again, we believe that the existing fiscal system is not optimal, mainly because of the property tax and the unvarying tax and royalty rates. Any variation of the property tax still incorporates regressive elements that present low price risk. When variations on elements of the state's fiscal system are pushed too far, they change the character of the property tax such that local communities are deprived of their essential tax base, and the state's share of the economic rent may be too low.

The results of modeling the major fiscal alternatives have yielded some encouraging results. They show that there is a wide range of alternatives for advancing both the state's and investors' objectives. It is possible to both improve the investors' return and increase the state's share of the economic rent under favorable conditions while, at the same time, not overly burdening the project when prices are low.

For example, a system that eliminates the four state fiscal components and replaces them with a profit system subject to the lookup table set forth above yields the following:

Market Price	Rate of Return	State Share of Rent
$2	6.26%	-18%
$3	10.08%	3%
$3.50	11.31%	11%
$4	12.20%	19%
$5	13.36%	33%
$6	14.44%	40%
$7	15.46%	44%
$8	16.44%	47%

D. Social Stress

As mentioned above, one very important positive aspect of the property tax is providing funds to meet social costs and stresses incurred by local communities during construction and operation of the project. While in other jurisdictions, where either personal income taxes or sales taxes provide a direct link between economic activity and local treasuries, in Alaska, with the exception of oil, new economic activity actually causes a drain of the state treasury.

If we are to replace the property tax with some kind of a profit-based payment, it would be important to establish a mechanism for dealing with the costs and social stresses that local communities would incur because under a profit-based system there would be no tax revenues during construction. This is the time when community impacts would be greatest. It may be possible to set aside money now such as other appropriated funds currently segregated in the state general fund and establish a program to distribute the money when needed.

During operation of the project it is possible that the sponsors could pay fixed amounts each year to the communities where they are needed. This amount could be deductible in determining the tax base.

At this time we have not yet undertaken the work necessary to project the cost of meeting this socioeconomic stress. Clearly, this should be a matter for continuing research and analysis.

E. Permanent Fund

Contributions to the Permanent Fund are based on royalties.[12] Replacing the royalty mechanism would create an uncertainty for determining the amount that must be contributed to the Permanent Fund. Keeping current lease terms, 12.5% of the wellhead value would solve this problem and would, at the time, assure the state of a minimum take. Currently, we believe that a progressive, back-end loaded profit system on top of the royalty, utilizing the same wellhead value, while reducing flexibility somewhat, would not be unduly onerous. We have not excluded, however, the possibility of a payment in lieu of royalty determined under some other methodology, in which case portions of the payment could be dedicated to the Permanent Fund.

VI. TIMING OF FISCAL DEVELOPMENT AND PROJECT STRUCTURE

We discussed above the possibilities of different parties upstream and downstream assuming either price or cost risk. This was referred to as project structure. One of the key elements in progressing an Alaska North Slope gas project is the establishment of a project structure. This involves determining who the participants are and how the risk and rewards are shared among those participants. As mentioned earlier, three simplified project structures were used in the economic evaluation. The differences in the project structures were the locations of the price and investment cost risks within the project.

The interrelation between project structure and fiscal system is complex. It is possible that the inherent differences, for example, between the first structure, where the producers retain cost and price risk, and the third structure, where another party purchases the gas at the lease boundary, could warrant different fiscal systems. Therefore, it may be inappropriate to design or negotiate a fiscal system until a project structure begins to emerge.

There are several reasons for this. First, depending on the structure of the project, it is unclear whether the profit is earned and measured upstream or downstream, or both. The answer could determine where the tax should be imposed, and who should pay it.

Also, if the upstream were selling the gas at the lease boundary and were responsible for the tax at the same time, the purchase price would implicitly include the tax. This added element might well increase the complexity of the price negotiations between the upstream producers and the downstream project investors.

Finally, it may seem reasonable that any significant participant who may be liable for a tax payment should not be absent from the negotiations. Accordingly, one can make a strong argument that the state should negotiate with the sponsor group, rather than with individual participants. The state would need to develop criteria for determining what constitutes a qualified sponsor group.

[12] 25% of royalties from Prudhoe Bay leases are contributed to the Permanent Fund.

Of course, this is not to say that project structure should necessarily precede fiscal system development. Some potential project participants may need to know exactly what the fiscal system is prior to becoming a participant in order to assess project viability. In addition, because of the long lead times and complexity of LNG projects, project structure may change during the commercialization process. Indeed, there may even be multiple project structures.

We believe that for now it may be prudent to see how project structure begins to form before designing and negotiating a detailed fiscal system. This would allow potential project participants to select the time that is most optimum for developing a fiscal system for their proposed project. This will help ensure that the project has the greatest chance to succeed in the long run because it will be attractive to the greatest number of potential project participants.

PART III

FEDERAL ACTION

The goal of the Federal Action working group was to identify appropriate federal fiscal actions, such as accelerated depreciation, that may enhance the competitiveness and economic feasibility of a North Slope gas project, and to explore options for achieving some or all of those actions.

I. FEDERAL BENEFITS

If a North Slope gas project moves forward, a principal beneficiary will be the U. S. government. The state's expert on fiscal regimes, Dr. Pedro van Meurs, suggests that if the project is built, the federal government could expect to receive more than $26 billion in corporate income tax revenue over the project's life. The project would also create jobs and the demand for materials and services throughout the nation, and assist the United States in balancing its payments and trade with Asia.

II. CHANGES TO FEDERAL FISCAL REGIME

The federal government can do a tremendous amount to improve the project's economic feasibility and competitiveness and thereby encourage its development. Dr. van Meurs identified several relatively modest changes to the federal fiscal regime that significantly improve the rate of return potential investors in the project could expect. Accelerating the rate of depreciation applicable to the project's assets is one. Under the current system, the project's principal assets would be depreciated over 15 years. Most countries with existing and potential liquefied natural gas (LNG) projects, however, allow depreciation over much shorter periods, typically five to 10 years. This is a notable disadvantage to the Alaska project, and one over which Alaskans have no direct control. A change in the federal depreciation schedule to bring the United States in line with its competitors would be one way for the United States to show support for a North Slope gas project.

Members of the Federal Action working group accompanied Revenue Commissioner Wilson Condon and Dr. van Meurs to Washington, D.C. Dr. van Meurs was invited to testify on July 23 before the Senate Energy and Natural Resources Committee, chaired by Alaska Senator Frank Murkowski, regarding the role foreign governments typically play in encouraging LNG export projects within their borders, and how the United States compares to these other governments in competing for a share of the Pacific LNG market.

Dr. van Meurs told the committee that although the demand for LNG in the Pacific is projected to grow rapidly, a large number of projects have emerged--in Australia, Canada, Russia, Malaysia, Vietnam, Indonesia, Papua New Guinea, Qatar, Oman and Yemen--to more than fill this projected demand. Many projects are competing for a limited market. Those projects offering the most competitive terms will be the most successful.

Many host countries recognize the competitive nature of the LNG market and compete aggressively for places in the market by, among other things, participating in project financing and structuring unique fiscal terms to fit the economics of their particular projects. As emerging projects enter the Pacific LNG market, it is clear that the playing field is anything but level.

The fact that the economic starting points for the competing projects are vastly different from Alaska is particularly bad news for the Alaska project. First, none of these other projects are burdened with the need to build an 800 mile buried pipeline to move their gas to tidewater. This is a huge capital expense and a giant hurdle to overcome when competing with other projects. In addition, the size of the capital investment needed to move Alaska gas to market requires long-term contracts for enormous volumes of gas, on the order of 14 million metric tons per year (about one-quarter (1/4) of the entire East Asian LNG market today). To be successful, the Alaska project must be able to secure a significant portion of the projected demand for LNG in the Pacific market. With a number of smaller projects potentially coming on line to fill demand in the Far East as it arises, there is a significant danger of the Alaska project being displaced, or, as some have observed, “nibbled to death”.

The other experts testifying before the Senate Energy and Natural Resources Committee confirmed Dr. van Meurs’s position. When it comes to the LNG export market, companies that want to do business in the United States are at a disadvantage. Countries like Qatar and Indonesia are willing and able to structure fiscal regimes around individual projects to maximize their competitive position. They are able to do so in ways that are favorable not just for the investors but for the government as well.

The United States is not competitive even against other western-style democracies The fiscal systems of Canada and Australia, for example, are considerably more favorable to investors in LNG projects than is the fiscal system of the United States.

Following the Senate hearing, Commissioner Condon, Dr. van Meurs and the Federal Action working group members met with officials at the departments of Energy, Commerce and State, and the Office of Management and Budget and the National Economic Counsel within the White House. The goal of these meetings was not to advocate any specific changes to the federal fiscal system but to discuss generally the potential benefits of the Alaska project to the United States as a whole and to gather insight, from the perspective of these federal agencies, on the willingness of the federal government to participate in creating a more competitive environment for developing the huge gas reserves on Alaska’s North Slope.

III. DIFFICULTIES TO ACHIEVING FEDERAL CHANGE

All of the federal officials recognized that North Slope gas is a resource of national importance and that the United States would reap significant benefits, in the form of revenue, jobs, and improvements in the balance of payments and balance of trade with Asia, should the resource be developed. They were also unanimous in recognizing the difficulties the state faces in convincing the federal government to be a player in creating a more competitive environment in which to develop the resource. There are several related problems.

A. Tax Policy

As a matter of general tax policy, the United States does not normally establish or adjust particular tax provisions to address the unique economic conditions faced by individual projects. A tax code whose particulars are generally applicable is a fundamental aspect of that policy.

B. Scoring

Any change in the tax laws is subjected to a unique method of "scoring" by the Joint Committee on Taxation, which is a way of measuring the effect of the proposed change on the federal treasury. Any change in the tax code designed to increase the competitiveness of U.S. projects in relation to foreign projects, even if it is to just "level the field," is unlikely to fare well in the scoring process. The reason is that scoring generally is not done on a dynamic basis. The process does not consider the fact that without the proposed change the project is unlikely ever to go forward. Instead, as a rule, the process assumes that the project will go forward under the federal government's current fiscal terms and compares the tax revenue assumed to be received by the treasury before and after the change.

C. Corporate Welfare

Any change in the tax code designed to make an American project competitive internationally may, at some point and by some observers, be branded as corporate welfare. This seems inevitable, no matter how clear the evidence that without changes in the fiscal system the resource simply will not be developed. It is part of the vocabulary and mind-set of the moment in Washington, D.C.

D. Environmental Impact

It was generally recognized throughout the federal government that the promotion of large-scale gas projects would assist in combating the negative effects of global warming. This may be an important point to engender federal support for the North Slope gas project.

IV. CONCLUSIONS

These problems are not necessarily insurmountable. The federal government has occasionally addressed the unique problems of a particular industry in the tax code in a way that advances national goals. Accelerated depreciation for semiconductor manufacturing plants and certain research facilities are examples. A related precedent is the royalty relief provided by the federal government to certain deep-water wells in the Gulf of Mexico. The LNG export industry is a truly unique one and may, given the current international climate in which LNG export projects are developed, deserve a separate look.

A negative score by the Joint Committee on Taxation also is not fatal, if there are sufficient national interests at stake to justify the change. The state may also be able to reduce or perhaps eliminate a negative score by conditioning its fiscal modifications upon the passage of federal legislation that improves the economic feasibility or competitiveness of stranded gas projects in Alaska.

The federal government must choose, as must the state, whether it is willing to compete in the Pacific LNG market on the terms set by the international community or whether it is content to leave the resource in the ground. Providing project sponsors in Alaska and the United States a fair opportunity to compete for a portion of the Pacific LNG market cannot legitimately be labeled “welfare.”

The burden is upon the state. Our discussions with congressional office representatives and federal administrative officials confirm that nothing will happen at the federal level until the state has taken the initiative and shown that it is willing to act, by restructuring its fiscal system in a way that improves the economic feasibility and competitiveness of the project.

Once the state has demonstrated its willingness to act, it must approach the federal executive and Congress with a plan for achieving specific changes at the federal level. This plan must be supported by clear and convincing evidence that the proposed changes advance the national interest.

PART IV

ALASKA HIRE

The goal of the Alaska Hire working group was to find suitable voluntary measures to successfully ensure that a maximum number of Alaska residents and businesses that are qualified or capable of being qualified in a competitive environment participate in the gas project.

I. BACKGROUND

The group's work was conducted against a background of U. S. and Alaska Supreme Court decisions. On three separate occasions, the courts struck down previous Alaska hire efforts, finding Alaska's attempts to require Alaska hire through legislation to be unconstitutional because the laws discriminated against nonresidents of the state and violated the U. S. Constitution's privileges and immunities clause or impermissibly discriminated among residents of the State of Alaska and violated the state constitution's equal protection clause.

These previous Alaska-hire efforts that were later overturned included a requirement for Alaska-hire preference for employment resulting from state oil and gas leases (Hicklin v. Orbeck, 1978); a requirement for local hire for state-funded construction projects (Robison v. Francis, 1986); and provision for regional hiring preference for residents of economically distressed zones (State v. Enserch Alaska Construction, 1989).

II. RECOMMENDATIONS

The Alaska Hire group sought to avoid these problems by recommending both requirements and voluntary measures for Alaska-hire efforts on the part of gas-export project employers. Required collected data would give specific and timely information to the governor, legislature and public on the success or failure of employers' voluntary Alaska hire efforts.

A. Recruitment and Residency Identification

Employers would be required to advertise in-state for positions, and use State of Alaska job service organizations to notify the Alaska public regarding jobs. Employers would also be required to identify employees and employers involved in project construction through quarterly unemployment insurance submittals to the state. The Department of Labor will create a statistical indicator of the number of Alaska residents and employees involved in project construction by comparing quarterly unemployment insurance submittals against other indicia of Alaska residency, such as Permanent Fund dividend qualification and driver's licenses.

B. Hiring, Training and Contracting

Because of constitutional limitations, employers would be encouraged, but not required, to undertake specific measures to hire qualified Alaskans; train Alaskans who are capable of becoming qualified; contract with Alaska businesses; and encourage contractors and sub-contractors to hire Alaskans and Alaska businesses.

C. Reporting

The state commissioner of Labor would be required to prepare and present to the legislature an annual report, by employer, regarding the number of Alaska residents working on the project. In preparing this report, the commissioner would be required to use state-compiled databases, including quarterly insurance submittals.

D. Definitions

Alaska residents would be defined as individuals who qualify for a Permanent Fund dividend or meet any two of the following indicia: Alaska voter registration; Alaska driver’s license; resident hunting, fishing or trapping licenses; or Alaska motor vehicle registration. Alaska businesses would be defined as contractors controlled by Alaska residents, have held Alaska business licenses for a year or have maintained a place of business in the state for a year, and deal in the type of supplies or services required for the gas-export project construction.

PART V

ROYALTY IN KIND/ROYALTY IN VALUE

The goal of the RIK/RIV working team was to recommend royalty-in-kind and royalty-in-value options that increase certainty, reduce risk and improve the commercial aspects of a North Slope gas export project, while protecting the state's overall interests in the North Slope natural gas resource.

I BACKGROUND

Under the terms of oil and gas leases the state can take its 12.5% royalty share of the gas either in value or in kind. When the state takes its royalty in value, the lessees transport and market all of the gas and pay the state its share of the revenue collected or value of the gas[13]. When the state takes its royalty share in kind, the lessees physically transfer possession of some or all of the royalty share to the state at the sales meter.

Currently, the state must give the lessees six months notice of its intent to take some or all of its royalty share in kind. It must also give six months notice to change or cancel an existing RIK nomination. However, with the proper six month notice, the state can change its in kind/in-value royalty split each month. The ability to constantly change the in kind and in-value royalty share each month adds uncertainty to a gas export project. Determining the state's long-term plans for royalty in-value and royalty-in-kind takings reduces uncertainty in pipeline throughput design and marketing decisions. It also puts in-state users of gas (local communities) along the pipeline corridor on notice that advance planning is necessary if the users want to access royalty or any other gas from the project early in the life of the project.

Determining a fixed long-term method to value any royalty gas taken in value will also reduce uncertainty for the project. Sponsors will know their royalty obligation at the time the gas is marketed and will not be subject to potential large audit claims after the fact. Several options for valuing state royalty gas are discussed later in this report.

II. ROYALTY IN KIND/ROYALTY IN VALUE

Certain provisions in the state’s oil and gas leases could be amended or appropriate legislation enacted relating to royalty that would help reduce risk and minimize uncertainty. In order to accomplish this, the state must be prepared to make these royalty-related decisions at the appropriate time in the project timeline. However, 1998 is not the appropriate time to make these decisions. It is premature to fix a royalty-in-kind share or a royalty-in-value calculation methodology given the uncertain nature of future in-state gas demand, the fiscal system that will govern taxes and gas netback pricing for the

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[13] The RIV/RIK group was not charged with determining price or value for any royalty gas sold in value.

project, and the overall project structure. However, these royalty decisions will have to be made well in advance of project start-up in order that Alaska communities can plan for local gas needs, project sponsors will know what gas reserves are available for export, and project sponsors can design for pipeline throughput needs.

In order for the state to gauge the demand for in-state gas, and provide some regular far-in-advance opportunity for parties to acquire North Slope royalty gas, some form of regular polling and royalty sale offering may be necessary. This concept of far-in-advance notice and sale would also let the project sponsors and prospective purchasers plan for additional needed throughput capacity and provide for “open season” nominations of any desired additional pipeline throughput.

With respect to the RIK gas volumes and in-state gas needs, one option available to the state and the local users is for the state to agree to leave all of its royalty gas in value in exchange for a promise from the project sponsors to agree to sell gas to local communities and users. Such an arrangement eliminates both the need for RIK sales by the state and the pipeline nomination difficulties the pipeline corridor communities would likely encounter, but would not eliminate the need for dedicated pipeline capacity for gas used in-state. The fiscal systems the Gas Commercialization Team is considering would accommodate this option.

Any revised royalty terms and conditions must be tied to a specific project scope (time and volume considerations). The RIK/RIV split would have to be set for a given time period or gas volume and the royalty valuation terms would have to be in effect for a given time period or cover a given gas volume. In addition, gas royalty treatment for extensions of existing contracts, project expansions and new contracts should be addressed separately.

III ROYALTY GAS VALUATION OPTIONS

Several options to value royalty gas have been proposed. One option is to use the same valuation method that is used in the tax related fiscal system--the “payment in lieu of” concept. This option should be considered as one of the choices for royalty valuation but not mandated as the only choice. A second option would be to negotiate a separate valuation method just for gas royalty valuation. Either of these options would require certain amendments to the existing oil and gas leases and gas royalty settlement agreements in order to harmonize the agreements and revise the RIK-taking provisions in the current leases. A third option would be to make no changes in the royalty arrangements at this time. Under this option, one would calculate royalty according to the existing settlements and leases and nominate taking royalty-in-kind gas likewise. There are at least two reasons for leaving the royalty provision alone at this time. First, the resource should have some value to the landowner. If it has no value, it should remain in the ground. Second, any change in the royalty system may well affect the contribution to the Permanent Fund and therefore significantly complicate negotiations.

If there are to be any changes in the royalty system, the commissioner of Natural Resources would have to be authorized either to agree to a formula royalty valuation method or to accept the value used for the “in lieu of” payment of taxes. This authority would be necessary because agreeing to a new method for determining royalty value for the gas might be a royalty reduction under current state law. The commissioner also would have to be authorized to enter into a fixed long-term RIK/RIV split for the royalty share of gas committed to the project.

If the royalty system is left in place, there may be some technical issues about how to value the gas that would have to be negotiated. This would provide some certainty both for the state and the producers but would not necessitate a change in the basic royalty structure.

IV. CONCLUSIONS

Amendments to the state’s North Slope oil and gas leases, gas royalty settlement agreements and oil and gas statutes can be made that would help reduce project risk and uncertainty. None of these actions or options are meant to unilaterally change or amend the leases or settlements as to the oil and gas that is already subject to existing settlements.

A. Timing

Decisions must be made relatively early in the project planning and design process concerning valuation of royalty gas and in-kind nomination of royalty gas volumes. These decisions and decision points have been identified. However, it is inappropriate at this time to amend the oil and gas leases, settlements and royalty statutes and make binding decisions concerning royalty in-kind volumes and royalty-valuation terms. Formulation of the appropriate fiscal system should proceed parallel to the royalty discussion. Therefore authorization to take such actions may need to be granted consistent with the granting of authority to establish the fiscal system.

B. Royalty

Amended royalty terms should be negotiated at the time specific fiscal terms and contracts are negotiated with project sponsors; the gas netback pricing method is set, in-state gas needs on the North Slope, along the pipeline corridor and in Cook Inlet are better defined; and timing of the pipeline construction and gas availability is better known.

Retaining a separate royalty payment of some type allows an easy calculation of payments to the Permanent Fund and school fund. Eliminating the royalty and adopting a “full payment in lieu of” fiscal system would require alternative treatment of Permanent Fund and school fund payments. In either case, the valuation basis and netback methodologies should be the same for both royalty and tax calculations.

The commissioner of Natural Resources should be authorized to agree to long-term gas royalty-in-kind and royalty-in-value nominations and to agree to long term gas royalty valuation methods for gas dedicated to the project.

Excessive detailed legislation and mandates covering royalty issues at this stage (1998) in the process would only serve to limit flexibility for the state, lessees and project sponsors and stifle creativity amongst the parties.

C. In-State Gas Needs

Potential in-state gas needs along the pipeline corridor have been identified. Possible gas uses and gas volumes have been discussed and quantified in a separate report[14]. The report also discusses the possible construction of a gas spur line to the Cook Inlet area and potential use of North Slope gas in the Cook Inlet area.

[14] The Potential In-State Demand for Alaska North Slope Gas by Daniel A. Zobrist, Division of Oil and Gas, Dept. of Natural Resources, State of Alaska, October 1, 1997

PART VI

COMMERCIAL REGULATION

The goal of the Commercial Regulation working group is to review the pertinent economic regulations imposed by the state and federal governments to determine if statutory changes need to provide the commercial certainty the project requires. The pertinent state economic regulations are set out in various state statutes – the Alaska Pipeline Act (AS 42.06), the State Right-of-Way Leasing Act (AS 38.35)- and the accompanying administrative regulations.

I. BACKGROUND

Representatives of the state departments of Law, Revenue and Natural Resources evaluated the state's laws that would impose economic regulation on the proposed gas project. After consultations with international experts with extensive experience in developing and marketing natural gas in the form of LNG, it became apparent that the state's current laws imposing economic regulation, while appropriate for the production and transportation of crude oil, are not suitable for an LNG project.

LNG projects are typically based on long-term contracts. In contrast, oil development projects are often based on the ability to sell oil under long-term, short-term and spot market sales contracts. Currently, the state's regulatory regime is designed to facilitate the development of oil resources utilizing an oil pipeline regulatory approach based on the principle of common carriage.[15] Common carriage requires the owners of an oil pipeline to carry oil from any producer that tenders that oil to the pipeline. If the pipeline has reached maximum capacity, then as new oil is tendered to the pipeline the volume of oil that shippers are able to send through the line must be prorated to allow shipment of newly tendered oil.

Common carriage and the threat of proration are generally considered unsuitable for long-term LNG contracts since shippers must be able to deliver firm contract volumes. In contrast to oil pipelines regulated under terms of common carriage, natural gas pipelines in other parts of the United States regulated by the Federal Energy Regulatory Commission operate under contract carriage regulations. Contract carriage regulation is more suitable for natural gas pipelines because gas shippers and producers are assured by contract that reserved capacity will not be prorated.

In light of the unsuitability of the state's current laws pertaining to economic regulation of an LNG export project the Commercial Regulation working group needed to explore other regulatory options.

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[15] Regulatory agencies consider the gas pipeline serving the LNG project in Kenai to be a field gathering line and therefore not subject to economic regulation.

II. DEVELOPMENT OF GUIDING PRINCIPLES

The first objective of the working group was to identify a recommended set of principles that appropriate state commercial economic regulation should follow. In order to develop these principles, the group had to first identify the critical commercial requirements for a viable LNG project.

A. Critical Commercial Requirements

These requirements are what the state's commercial economic regulation must provide for a project to go forward.

1. Guarantee pipeline capacity for LNG volumes.

2. Minimize project costs to encourage investment.

3. Reduce regulatory uncertainty. It is unclear which state or federal agency will regulate the pipeline, whether commercial regulations would be light or heavy-handed, and what parts of the transportation system-including the conditioning plant and liquefaction facility as well as the pipeline-would be regulated.

4. Allow flexibility for different project structures. For example, one investor may own the pipeline, another may choose to invest in liquefaction, while others may invest in marine transportation. Investors in the project and gas resource owners should be able to choose their desired business arrangement for sharing both the revenue from gas sales and the risks of fluctuations in gas prices and project costs.

5. Assure that owners of the gas will receive, if possible, a positive price from the start for supplying gas to the project.

6. Provide an incentive for potential gas shippers to invest early in the project to avoid the free-rider problem.

B. Guiding Principles

Based on these critical commercial requirements and the current uncertainty regarding state or federal regulation, the working group developed the following principles the state's economic regulations should follow:

1. Guarantee access to pipeline/facilities for LNG firm contract volumes.

2. Encourage future gas exploration by providing reasonable rates and access to pipeline/facilities or excess/expansion capacity for new shippers.

3. Provide an innovative, stable-rate methodology for the pipeline/facilities over the life of the project.

4. Provide reasonable access and rate structure for in-state gas sales and service.

5. Recognize market forces in the LNG business.

6. Clarify the scope of project regulations and the regulatory regime to encourage investment.

These principles represent a combination of important state interests and the critical commercial requirements identified above. The state has an interest in seeing that in-state users have access to natural gas. Communities along the anticipated pipeline corridor now use expensive coal or fuel oil because they lack access to natural gas. The Cook Inlet area might need additional volumes of natural gas besides that provided by Cook Inlet fields.[16] The working group agreed that local sales should not make the project a utility under the state's utility act, thereby subjecting the project to burdensome regulation. The state also has an interest in having the pipeline encourage further exploration and development of Alaska's gas resources.

III. IMPLEMENTATION OF PRINCIPLES

A. Pipeline Access: Common vs. Contract Carriage

The working group determined the changes needed in the state's current economic regulations consistent with the agreed-upon principles. The group agreed that provisions in the state law requiring a gas pipeline to be a common carrier should be changed. The pipeline should be regulated as a contract carrier in order to ensure that LNG buyers receive a secure supply. The group looked at how FERC regulates gas pipelines for guidance as to how contract carriage worked.

B. FERC Gas Pipeline Regulation

1. Nondiscriminatory Access

The FERC requires that a pipeline offer access to potential shippers without undue discrimination. Under FERC rules, a pipeline cannot give preference to certain shippers - its affiliates, for instance - thereby precluding other shippers from an opportunity to compete fairly for pipeline capacity. FERC follows this nondiscrimination principle both in the initial allocation of pipeline capacity and in the subsequent allocation of uncommitted or expansion capacity.

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[16] The Team reviewed a study of anticipated demand for North Slope gas done by petroleum economist Dan Zobrist of the RIK/RIV committee.

2. Open Season to Allocate Access

FERC requires that a pipeline allocate capacity by soliciting offers for that capacity from potential shippers. This is called "open season". In this "open-season" process, a pipeline provides notice of the terms and conditions under which it will ship gas, and any potential shippers accepting these terms can bid for pipeline capacity. A pipeline must evaluate bids in a nondiscriminatory manner.

In addition to ensuring non-discriminatory allocation of capacity, having an open season before construction begins would force a shipper to commit to take a certain capacity before the pipeline is built. A pipeline will offer capacity on a firm basis - that is, it will guarantee a shipper a certain capacity if the shipper commits to pay for that capacity in the line if the pipeline is built. Once capacity is committed subsequent shippers will not be able to prorate down or use any part of the committed, firm capacity. The firm capacity bids received during an open season let the pipeline designers know how to size the pipeline so it has the required capacity without having wasted, unused capacity in the line.

The working group agreed that some form of open season should be used to allocate the gas line's initial capacity.

3. Evaluation of other FERC Access Allocation Provisions

Some of the pipeline's capacity might not be committed in an initial open season for several reasons. First, a pipeline and a conditioning plant might be able to handle more gas than anticipated. Second, sometime in the future, a pipeline's capacity might be expanded to handle more gas. Third, a shipper might not be able to use all of its capacity. The law governing the FERC regulation of gas pipelines provides for the allocation of this uncommitted or expansion capacity. The working group agreed that the state's economic regulations should specify how these volumes should be allocated if it turns out there is excess capacity or a pipeline expansion. The group also agreed that the suitability of FERC rules for an LNG export project will require further research and discussion.

IV. SCOPE OF REGULATION

A. What Kind of Regulatory Framework Should Apply to the Conditioning Plant and the Liquefaction Facility?

The working group agreed that a state agency should regulate the pipeline. However, an ANS gas project would include more than a pipeline. There would be a conditioning plant at the front end of the pipeline and a liquefaction facility at the tail end of the pipeline. These facilities could either be viewed as private facilities that fall outside a regulator's purview or as integral parts of the pipeline.

The proposed conditioning plant would be an expensive facility, anticipated to cost at least $1 billion. The working group discussed whether regulations regarding pipeline access should also apply to the conditioning plant. Working group members expressed various concerns. The plant may be a non-unit facility to which some owners of Prudhoe Bay Unit gas may not have access. Even a unit facility might still be inaccessible to some gas owners on the Alaska North Slope.[17] Access to the pipeline may mean little if access to the conditioning plant was not available and a small conditioning plant was uneconomic. However, imposing access regulations on a conditioning plant might discourage investment in the plant and the project. Gas owners who didn't own a part of the conditioning plant could still negotiate terms for access to the plant. A conditioning plant could be considered like a gathering line or production facility, and therefore outside the ambit of pipeline regulators.

The group also discussed whether access regulations should apply to the liquefaction facility. A gas owner would need access to the liquefaction plant, or would need to build another liquefaction facility, in order to economically transport gas to Asian markets. A gas owner without access to the liquefaction facility could still sell gas to in-state users.

The working group will hold fuller discussions on these subjects in subsequent meetings.

V. ENGINEERING EVALUATION OF PIPELINE CAPACITY

At a joint technical conference with the RIK/RIV working group, the state representatives learned about factors affecting the capacity of an ANS gas project, and the ability of such a project to expand capacity. The presentations made it clear that the project might have excess capacity. In other words, the project could turn out to be able to handle a volume of gas in excess of that project's nominal design capacity. Presenters also indicated that building a project for easy expandability to accommodate larger volumes (a larger diameter pipeline) probably requires some additional investment. Reinforcing the need for an early open season, the presenters stressed that from a design standpoint it is important to know the anticipated gas volumes.

VI. DRAFT REGULATORY CHANGES

The working group has discussed three different methods of embodying changes to the economic regulations. These are amending existing statutes and regulations, drafting a new statute and regulations, and drafting a new statute and making a economic regulations a part of an enforceable contract between the state and the project participants.

The working group has not yet reached consensus on which approach is appropriate.

[17] While the fields in the Prudhoe Bay Unit contain the vast majority of discovered Alaska North Slope gas reserves, other fields also contain gas.

APPENDIX A

Letter from Arco Alaska, Inc.

APPENDIX B

Letter from BP Exploration (Alaska), Inc.

APPENDIX C

Letter from Exxon Company USA

APPENDIX D

References

1. van Meurs, Pedro, “Suggestions for New Terms for the Alaska North Slope LNG Project”, van Meurs & Associates Limited, Calgary, Alberta, Canada, 1997. Includes executive summary and appendices.

2. Zobrist, Daniel H., “The Potential In-state Demand for Alaska North Slope Gas”, Division of Oil and Gas, State of Alaska Department of Natural Resources, October 1, 1997