

ALASKA LEGISLATURE SPECIAL COMMITTEE/SUBJECT FILES 8672
2930 SCOMM 128: HOUSE SPEC.COMM. ON OIL AND GAS, 2001-02 694

Table 4-4. NSB Value-added Estimates for Exploration, Development, and Production of Anadarko/AEC ANS Foothills Gas Operations, 2001-2030

	Value Added (Millions of 2001 \$)			
	Exploration	Development	Production	Total
Direct	45.9	300	125.6	471.4
Indirect	2.5	6.3	2.3	11.1
Induced (household expenditures)	1.0	5.0	5.3	11.4
Induced (government expenditures)	12.6	79.7	50.8	143.1
Total	62.0	391.0	184.0	637.0

Source: Northern Economics, Inc. and Anadarko/AEC

4.3 Impacts on the Alaska Permanent Fund

The Permanent Fund was established through a Constitutional amendment approved by Alaska voters in 1976. The amendment set aside at least 25 percent of all mineral lease rentals, royalties, and royalty sales paid to the State to be deposited into a public savings account to be invested for the benefit of the current and all future generations of Alaskans. A Permanent Fund Dividend was first paid to eligible Alaska residents in 1982. In 1999, total Permanent Fund Dividend payout was \$987.3 million.

The proposed ANS foothills natural gas production will generate additional Permanent Fund receipts amounting to 25 percent of the gas lease rentals, royalties, and royalty sales paid to the State. Over the life of the natural gas project, an estimated \$290 million of projected royalty payments will flow to the Permanent Fund. Using an estimated 5.25 percent of the principal for dividend payouts, total estimated Permanent Fund dividend payout is \$135 million. The estimated economic impacts from these annual payouts are 950 full-time jobs, \$33 million in labor income, and \$67 million in value-added.

4.4 Benefits to Consumers from Lower Energy Costs in Fairbanks

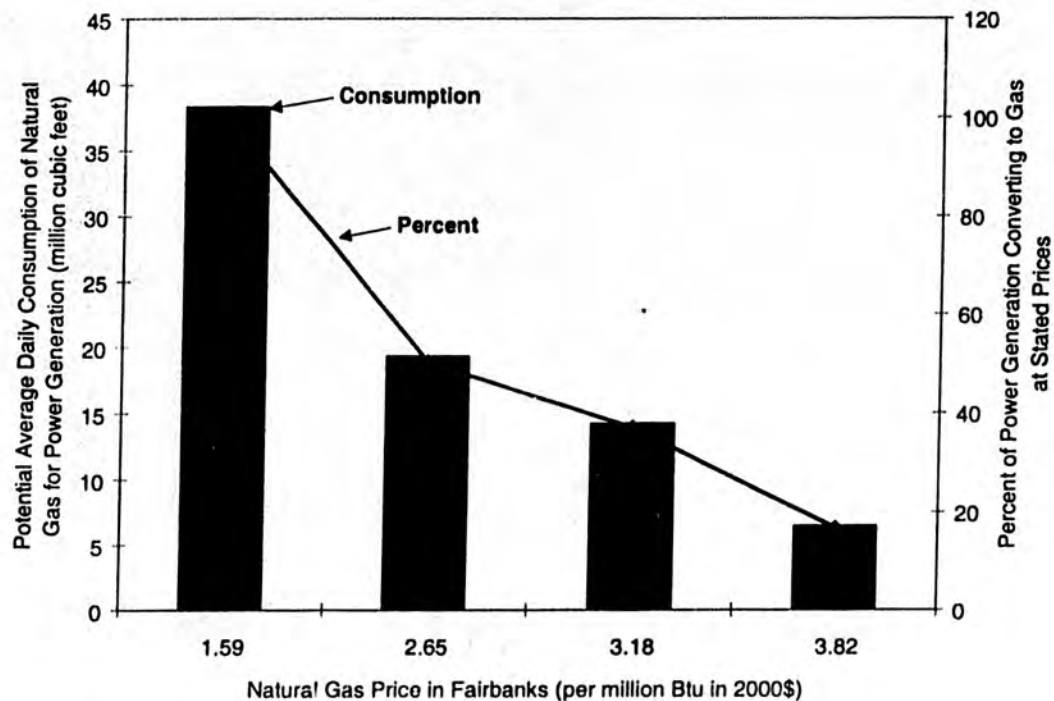
This section provides an analysis of the effects of the availability of natural gas on residential energy costs. The ANS gas project is expected to produce gas at a rate of 350 MMcfd from 2011-2015, 850 MMcfd from 2016-2030, and gradually declines to 407 MMcfd in 2030. This increase in natural gas production as a result of the ANS gas project, assuming a southern route gas pipeline is in operation, would represent an increase in the availability of natural gas for in-state consumption. Consequently, this may result in lower energy costs if the price of natural gas is low enough to allow for conversion of electric/heating generation from other sources to natural gas.

The community of Fairbanks is the largest community in interior Alaska. The Fairbanks North Star Borough has a recorded population of 82,840 residents. Hence, the area represents the largest potential demand for natural gas in the interior. This section looks at the possible benefits of lower energy costs to Fairbanks residents only.

Consumer benefits are realized only if the price of energy supplied by gas in comparison to the price of energy generated from other sources is lower. Utilities, businesses, and residents are not likely to convert to natural gas for their energy needs if it will cost them more to do so compared to costs from existing power generation systems. Electric energy in Fairbanks is mostly generated from a coal-fired power plant located in Healy, Alaska. In addition, an electric transmission line supplies access to low cost electricity generated by gas-fired turbines in southcentral Alaska. However, the transmission line can only support a portion of the Fairbanks electric demand. Heating demand in Fairbanks is met mostly with heating fuel refined in several local refineries. The refinery gate price for No. 2 heating fuel in August 2000 was about \$0.93 per gallon or \$6.70 per million British thermal unit (Btu).

A 1997 survey by the Alaska Department of Natural Resources (Zobrist 1997) indicates that power generators would be willing to pay only \$2.50 per million Btu (in 1997 dollars) to consider converting to natural gas. With a higher gas price there may not be enough incentive to switch to natural gas. Figure 4-3 shows the estimated daily natural gas usage for power generation at different prices. The gas price that would induce utilities to convert is relatively low because capital investments in existing coal-fired power plants are debt free and capital costs may increase substantially with conversion. Also, coal is relatively low in price for at least one major utility.

Figure 4-3. Amount of Fairbanks Power Generation Converting from Coal and Diesel to Natural Gas at Different Gas Prices



Source: Adapted from Zobrist, 1997.

A switch to ANS gas that would merely displace the existing uses of state resources may not offer significant net benefits to the state or regional economies, especially if it means eliminating jobs (at the coal-fired power plant). Subsidies to the power generators, in the form of grants to convert to gas-fired generating equipment and compensate for potential stranded assets, may be required for the power generators to switch fuels. Alternatively, subsidies could be employed to lower the price of natural gas sold to the power generators and other customers.

5 References

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**Notice of Clarification
Regarding State of Alaska Solicitation for Offers to Purchase
Alaska North Slope Royalty Gas
dated December 26, 2001**

The purpose of this notice is to clarify and update the State of Alaska's Solicitation for Offers to Purchase North Slope Royalty Gas, dated December 26, 2001. This notice clarifies that the State's Solicitation for Offers is seeking proposals for consideration under the procedures set out in 11 AAC 03.030-11 AAC 03.070.

The State hereby notifies all prospective buyers that their proposals must be consistent with the terms of the Solicitation for Offers, as clarified herein, and the procedures set out in 11 AAC 03.030-11 AAC 03.070 and will be evaluated under the criteria set out in AS 38.05.183(e).

The deadline for submitting applications for qualification is extended. Prospective buyers should not submit their applications for qualification by January 17, 2002, but must include the applications with their proposals, which remain due on January 31, 2002. The State will open the proposals on February 1, 2002. Except as set out above, the dates and procedures in Sections 17 and 18 of the Solicitation for Offers no longer apply.

The State reserves the right, after the proposals are opened, to negotiate terms before it awards sale contracts. The Commissioner will evaluate the proposals under the criteria set out in AS 38.05.183(e) before announcing which proposals, if any, have been selected for further consideration. If, after further consideration, the Commissioner believes a disposition of RIK gas under 11 AAC 03.030-11 AAC 03.070 is in the best interests of the State, the Commissioner will make a preliminary determination to award a sale contract to the prospective buyer, or buyers, whose proposal reasonably offers the maximum benefits to the citizens of Alaska, as provided under 11 AAC 03.060.

The Commissioner will provide public notice of the preliminary determination under 11 AAC 03.020(c). After considering public comments, the Commissioner will make a final determination whether an award of a sale contract to the prospective buyer, or buyers, is in the best interests of the State, as provided under 11 AAC 03.030(b).

Questions may be directed to:

Kevin Banks
Division of Oil and Gas
550 West Seventh Avenue, Suite 800
Anchorage, Alaska 99501-3560
(907) 269-8781
e-mail: [kreb@dnr.state.ak.us](mailto:krb@dnr.state.ak.us)

Final
Finding and Determination
For a Solicitation for Offers to Purchase
Alaska North Slope Royalty Gas



550 West 7th Avenue, Suite 800
Anchorage, Alaska 99501-3510

December 26, 2001

I. INTRODUCTION AND BACKGROUND

The Commissioner of the State of Alaska Department of Natural Resources has determined that it is in the best interests of the State to solicit offers to purchase, in competitive sale, a portion of the State's royalty share of natural gas (Royalty Gas) that may be produced from Alaska's North Slope (ANS) upon completion of a natural gas pipeline. Because of the possibility of an "open season" in 2002 for nominating shipping space on a future gas pipeline, an offer to sell now responds to a commercial opportunity to improve the State's future royalty revenues from ANS natural gas and promote new private investment in the State.

On December 26, 2001 the department will issue a Solicitation for Offers to Purchase ANS Royalty Gas. Proposals offering to purchase Royalty Gas must be received by the Division of Oil and Gas no later than January 31, 2002. The department will open the offers at a public meeting on February 1, 2002, but the department will not determine which proposals will result in contract awards until it has evaluated all the proposals. The department intends begin negotiating royalty in-kind (RIK) gas sale contracts with successful proposers in February 2002. The solicitation and sale schedule is detailed in section D below.

On October 29, 2001, the department issued a "Preliminary Finding and Determination for a Competitive Sale of Alaska North Slope Royalty Gas" (Preliminary Finding) and solicited comments from the public.¹ During the comment period, the Alaska Oil and Gas Royalty Development Advisory Board (Royalty Board) convened a public meeting to discuss the merits of a sale and take public testimony. After review of the Royalty Board's and public's comments on the Preliminary Finding the commissioner has determined that a competitive sale of the State's royalty share of ANS gas at this time is in the State's best interest. The "Final Finding and Determination for a Solicitation for Offers to Purchase Alaska North Slope Royalty Gas" (Final Finding) documents the commissioner's determination.

The commissioner reserves the right to cancel or postpone the solicitation for offers and the competitive RIK sale at any time. After the RIK sale is conducted, the State will negotiate the final contract terms with successful buyers. No RIK gas sale contracts that result from the RIK sale will be effective until they are approved by the Legislature.

A. Background

Under the terms of most of its leases with North Slope oil and gas producers, the State has a right to one-eighth of the oil and gas production as its royalty share. Some leases provide for higher royalty rates. The leases, along with various unit agreements and royalty settlement agreements, grant the State the right to take its royalty share of oil and gas production in-kind (RIK) or in-value (RIV). When the State takes its royalty share as RIV, the lessees market the royalty share and pay the State the cash value received. When the State takes its royalty share as RIK, it takes possession of the oil and gas and sells it in the market.

Currently half of the royalty oil production at the Prudhoe Bay Unit (PBU) has been taken as RIK and sold to Williams Alaska Petroleum, Inc. for use in Williams' North Pole refinery. The

¹ Written public comments and the State's responses appear in Appendix A and B.

State has also sold other volumes of oil as RIK to various purchasers in the past. Current North Slope royalty gas production is less than 4,000 Mcf per day.² The State has elected to take its royalty share of gas in-value and the lessees have sold to ANS utilities and the Trans-Alaska Pipeline System (TAPS) as fuel.

B. Why have a competitive RIK gas sale now?

Successful development of the vast ANS natural gas resource has challenged the State and the oil producers since the Prudhoe Bay oil field was first discovered. In the last year the major ANS oil and gas producers have renewed attempts to evaluate the challenges of transporting ANS gas to market. Construction of an ANS gas pipeline is by no means certain. But if a new gas pipeline were built to deliver natural gas from the North Slope to markets in the U. S. Lower 48 or elsewhere, the State's royalty share could rise to 500,000 Mcf per day or more by the end of the decade.

There are several important reasons for the State to conduct an immediate ANS RIK gas sale. First, potential buyers are motivated to purchase RIK gas at this time in order to be able to nominate capacity on the gas pipeline during an "open season," which is currently expected to occur in 2002. An "open season" is an opportunity during the early stages of a proposed pipeline's design for potential owners to invite potential shippers to secure transportation capacity on the future pipeline. An open season nomination is a firm commitment by the shipper to fill the capacity it nominated when the pipeline is operational or to pay demand charges for the unused space. It is an important (and often required) step in the process of applying to the U.S. Federal Energy Regulatory Commission (FERC) and the Canadian National Energy Board (NEB) for the certificate of public convenience and necessity for a pipeline.

In recent months companies have expressed interest in securing a gas supply from the State as a precondition to their participation in an "open season" for a future Alaska gas pipeline. Companies have suggested using RIK gas for marketing in the Lower 48, for potential in-state petrochemical plants, and as a "back-stop" to gas production for North Slope lease holders. The State also received a proposal in December 2000 to buy gas to fuel a power plant for a large Internet data center on the North Slope.³ With a gas sale contract from the State in hand, these companies could reduce some of the risk involved in committing to pipeline space in the open season.

Second, the sale of RIK may contribute to earlier commercialization of ANS gas and the successful completion of a pipeline by bringing additional participants to the open season. Evidence of additional participants interested in purchasing and transporting Royalty Gas on an Alaska gas pipeline could influence the timing and design of the pipeline.

Third, as discussed further in the explanation of Royalty Gas sale contracts, the State will receive more royalty revenues by taking the gas in-kind and disposing of it through an RIK sale than it would receive if the royalty gas were left in-value and marketed for the State by the lessees.

² Mcf = one thousand cubic feet; Bcf = one billion cubic feet.

³ The Alaska Legislature passed a resolution directing the department to consider sale of RIK gas for this purpose. (22nd Legislature; SCS CSHCR 17)

Finally, the RIK gas sale may attract proposals from other in-state buyers who would use the gas on the North Slope or buyers who may wish to supply in-state utilities or industrial users along the pipeline route.⁴

The State cannot guarantee when or if the ANS RIK gas it is proposing to offer for sale now will ever be delivered. But the prospects for an ANS natural gas pipeline project and an upcoming "open season" for nominating transportation capacity on a future gas pipeline has presented the State with an opportunity now to offer a portion of its future Royalty Gas as RIK in a competitive sale for delivery when an Alaska gas pipeline is developed.

C. What happens next?

Since publication of the Preliminary Finding, the Division of Oil and Gas has met with the Alaska Natural Gas Pipeline Project Team (ANGPPT), a consortium of the three largest ANS oil and gas producers. The ANGPPT indicated that an open season would not occur in the first quarter 2002 as had been assumed at the time of the Preliminary Finding. For this reason the department has extended the time schedule for some steps listed in the Preliminary Finding. Because the 2002 Legislative session will end in May, however, any RIK gas sale contracts submitted to the Legislature have to be negotiated by the end of the first quarter 2002.

The next step in the process is publication of a Solicitation for Offers to Purchase RIK Gas. The Solicitation will specify certain conditions of the offering, including the quantity of gas offered for sale, the term of the sale contract, the point of delivery, the date that proposals are due, and qualifications to participate in the sale. It will request that potential purchasers to submit proposals that specify terms the purchaser would like to include in a final RIK gas sale contract with the State. The Solicitation for Offers will provide at least 30 days notice to potential purchasers and indicate where the various application documents may be obtained.

Because of the current uncertainty surrounding completion of a gas pipeline project and a potential completion date still many years off, detailed contract requirements that are normally found in an RIK gas sale contract have yet to be developed. The Solicitation will include a sample RIK gas supply sale contract that illustrates the type of contract the State expects to negotiate for the sale of its Royalty Gas ("*Sample Contract*"). The *Sample Contract* is intended to be illustrative only; it will not contain all the terms that will appear in the final contracts.⁵ The *Sample Contract* will specify certain standard contract terms that are generally included in the State's final contracts, such as payment, default, security, and warranty clauses. Other contract terms, such as the base price to be paid for the gas, quantity purchased, volume measurement, and the timing of gas deliveries, will be negotiated after proposals are opened.

Offers must be received by the Division of Oil and Gas by no later than January 31, 2002. The department will open and announce the offers at a public meeting on February 1, 2002. But the successful offers will not be announced until after the department has evaluated all the proposals

⁴ Other North Slope uses could conceivably include a gas-to-liquids plant, a small plant to make methanol for oil field operations, or enhanced oil recovery (EOR) projects in fields outside of the Prudhoe Bay Unit.

⁵ A copy of the *Sample Contract* is attached to this Final Finding in Appendix D.

offered. The department expects the offers to present a number of variable terms and conditions that the department will need to evaluate and recommend to the commissioner before they are awarded. The department intends to complete the evaluations and notify the potential buyers whether their offers have been accepted no later than February 2002. After the offers are accepted the department will begin negotiating RIK gas supply contracts with the buyers.

Upon written request of the potential purchaser, the commissioner will hold as confidential to the extent provided by AS 38.05.035(a)(9)(D), any cost, financial or other proprietary information contained in an offer. All offers will be made public when the department submits the RIK gas sale contract to the Royalty Board, except as otherwise provided by law.

If the commissioner rejects any offers received under the solicitation, the commissioner will notify the Royalty Board and document the reasons for the rejection. As provided in 11 AAC 03.210 and 11 AAC 03.230, potential purchasers whose offers were rejected may request a conference with the commissioner before any contracts are executed.

Finally, the negotiated RIK gas sale contracts will be submitted to the Royalty Board for review and approval at a public meeting. The contracts will then be forwarded to the Legislature for approval with the Royalty Board's recommendations.

D. Schedule for Offers and RIK Gas Sale

The table below summarizes the schedule for the State's RIK gas sale purchase solicitation. Under this schedule successful RIK gas purchasers should know by March 2002 whether the commissioner and the Royalty Board have approved their contracts.

Schedule for the 2002 Solicitation for Offers to Purchase ANS RIK Natural Gas Sale	
Publish Final Finding and Solicitation	December 26, 2001
Proposals due at Division of Oil and Gas	January 31, 2002
Public opening of RIK Proposals	February 1, 2002
<i>The following dates are tentative and may be delayed or cancelled</i>	
Award Successful RIK Proposals	February 15, 2002
Publish Notice of Royalty Board Hearing	February 15, 2002
Convene Royalty Board Hearing	March 1, 2002
Executed RIK gas sale contracts to Legislative for approval	March 15, 2002

II. DEVELOPING RIK GAS PURCHASE PROPOSALS

A. To be considered, proposals must meet the following Minimum Cash Bonus and Base Price conditions.

Minimum Cash Bonus: In order to participate in the competitive sale, potential buyer's offer must include a minimum cash bonus. The minimum cash bonus must equal \$1.00 per Mcf per day of Maximum Quantities the buyer proposes to purchase (see the *Sample Contract* at Article

3.1.1.). For example, if a potential buyer proposes to purchase 200,000 Mcf per day of the State's royalty gas, it must include a minimum \$200,000 cash bonus with its proposal. If the quantities of RIK gas the potential buyer proposes to purchase will vary from season to season during the life of the contract, the offer should include a cash bonus based on the period of greatest quantity.

The State will initially retain the minimum cash bonus submitted with the successful offers and refund the cash bonuses of the offers that are rejected. The minimum cash bonuses of the successful offers will be refunded, without interest, if the Royalty Board or Legislature has not approved the final contracts by August 31, 2002, or if an open season has not occurred by December 31, 2004, or if an ANS gas pipeline is not in service or royalty gas has not been delivered to the pipeline by July 31, 2012. (See discussion of Term below.)

Base Price: The potential purchaser must offer a base price. For the purposes of this competitive RIK sale "Base Price" is as defined in paragraph 3.3.1 in the *Sample Contract*. It will be the higher of a fixed dollar per-volume unit price or the volume-weighted average of the amounts paid by the lessees on royalty gas left in-value (RIV). (See 11 AAC 03.210 (c).)

The State will consider offers that include a different mechanism to calculate the Base Price so long as it satisfies the definition of Base Price as the volume-weighted average of the amounts paid by the lessees on royalty gas left in-value (RIV). If the State is not satisfied with a proposed Base Price mechanism, the State will detail an acceptable mechanism.

The mechanism for calculating the value of RIV is set out in the State's current leases, unit agreements and royalty settlement agreements. A majority of the gas-producing leases in the Prudhoe Bay Unit (PBU) and the Point Thomson (PTU) Unit are the State's Form DL-1 leases that contain the following RIV value terms.

ROYALTY IN VALUE. At the option of Lessor, which may be exercised from time to time upon not less than six months' notice to Lessee, and in lieu of royalty in kind, Lessee shall pay to Lessor the field market price or value at the well of all royalty oil and/or gas. All royalty that may become payable in money to Lessor shall be paid on or before the last day of the calendar month following the month in which the oil or gas is produced. The payments shall be accompanied by copies of run tickets or other satisfactory evidence of sales, shipments, and amounts of gross production. (Form DL-1 lease at paragraph 15)

PRICE. The field market price or value of royalty oil or gas shall not be less than the highest of: (1) The price actually paid or agreed to be paid to Lessee at the well by the purchaser thereof, if any; or (2) The posted price of Lessee in the field for such oil or gas at the well, if any; or (3) The prevailing price received by other producers in the field at the well for oil of like grade and gravity or gas of like kind and quality at the time such oil or gas is removed from said land or run into storage, or such gas is delivered to an extraction plant. (Form DL-1 lease at paragraph 16)

In the event of a major gas sale, the lease language above, together with the provisions of unit agreements, royalty settlement agreements, or new settlement language, will define value for much of the RIV gas. Although the lease terms were disputed in the ANS Royalty Litigation, many issues were resolved as the litigation progressed. For example, the State agreed to pay field costs on PBU RIK gas. The State and the lessees in several royalty settlement agreements have also resolved the question of value with respect to RIV oil and natural gas liquids (NGLs). The royalty settlement agreements also define value for the current production of RIV gas.

The final determination of RIV value may take several years after the gas is delivered. For example, implementation of the lease terms to determine the value of RIV gas typically requires the State to audit the lessees for gas sale receipts and transportation cost deductions. The State then assesses the effect of terms, like those quoted above from the Form DL-1 leases that contain "higher-of" provisions to determine the final value for RIV gas. Additionally, retroactive changes in transportation or processing charges could result in changes to the RIK gas Base Price. Accordingly, the RIK gas buyer will have a contingent liability for upward adjustments in the RIK gas Base Price that may take several years to finally determine.

The RIK buyer is also subject to the possibility that the State and one or more lessees may settle an RIV obligation by invoking a different methodology than that specified in the leases. If the State and a lessee agree to define the method of valuing RIV differently than the leases currently specify, the Base Price of the RIK gas sale contract could be affected. It would still be calculated using the weighted-average of the amounts paid by the lessees on royalty gas in-value, but would use the newly agreed-upon values. This could result in application of different Base Price calculations and different timeframes for adjustments under the affected leases.

Price Premium: Potential Buyers may offer a Price Premium over the Base Price. A Base Price premium might be structured as a flat, per-unit addition to the Base Price, or a percentage of the Base Price added to the Base Price.

Option Price: An option price or fee could be offered for the ability to increase or decrease the quantity the buyer would purchase during the life of the RIK gas sale contract. The *Sample Contract* provides a mechanism for the buyer to reserve a quantity option. (See e.g. *Sample Contract* at Article 3.1.2- reduction, 3.4-reservation fee, and 9.4 termination fee.)

B. In addition to the required Minimum Cash Bonus and Base Price, an offer may propose Special Commitments.

Potential buyers may offer Special Commitments in addition to the minimum cash bonus and Base Price. A potential buyer is not required to propose a Special Commitment; however, Special Commitments may be given weight in the State's evaluation process. In order to be given weight in the evaluation process, the benefits to the State of special commitments must be quantifiable.

A Special Commitment could be a commitment to in-state processing, in-state use, in-state investment, in-state exploration, local hire, or anything else that a potential buyer offers to enhance its proposal. But, such commitments must be measurable and enforceable. Forecasts or

other reasonable statistical measures that indicate the in-state economic and social benefits they afford should be provided.

Among the in-state benefits the State will consider are the economic and social benefits of increased employment, increased household incomes, in-state construction, purchases of local and state goods and services, consumer benefits in the form of lower cost energy, local and state property taxes, corporate income taxes, and economic growth in related industrial sectors. (A listing of these considerations is found in AS 38.06.070.)

If a proposal includes in-state investments and asks the State to consider the benefits offered by Special Commitments, it should describe the Special Commitments to incorporate into the RIK gas sale contract as performance obligations. For example, if an offer proposes benefits from in-state investments it should include quantifiable performance standards. If an offer proposes benefits from in-state use of the RIK gas, it should provide a mechanism to assure that the gas purchased under the contract will be used in-state. It should also offer some restriction on the re-sale of the RIK gas beyond adjustments required for the efficient operation of the buyer's facilities.

Special Commitments and performance obligations will be subject to all contract remedies available to the State if a buyer fails to meet its performance terms. These may include cancellation of the sales contract, substitution of performance obligations, reduction in sales volumes, damages and other remedies available at law.

C. Proposals should address the following terms and conditions as specifically as possible.

Quantity: RIK proposals must specify the quantity of gas desired. The State's royalty share from the ANS leases is not a specified daily quantity, but rather a specified percentage of production. The State recognizes, however, that potential RIK purchasers who expect to participate in an open season will want to contract for a specified daily quantity of gas. For this reason, the State's draft *Sample Contract* assumes that royalty gas will be measured volumetrically in Mcfs, but for a final RIK gas sale contract it may need to be converted to percentage of production.

No Guarantee of Quantity: The State cannot guarantee a certain quantity of gas under an RIK gas sale contract supply. The State can deliver royalty gas only to the extent it receives royalty gas from the lessees. The quantity of royalty gas available to the State may vary and may be interrupted from time to time depending on a variety of factors, including the rate of production from the leases and unit. Furthermore, the State may be required to nominate royalty gas as a percentage of its total royalty gas, and not by quantity. Accordingly, prospective buyers must be willing to accept the risk of receiving more or less than the desired quantity at any given time.

The State will consider offers that request seasonal variations in quantity, but the proposal should include a schedule that predicts by month, year or season the quantity that will be required throughout the term of the contract. Potential purchasers should be aware that in order to vary the quantity of royalty the it takes in-kind under any lease, the State must provide several months' notice to the lessee depending on the terms of the lease, unit agreement, or settlement

agreement. For instance, the State must nominate RIK gas in the PBU at least six months before the production month in which the nomination will be effective.

The State and the successful purchaser will ultimately negotiate a Maximum Quantities term for the final RIK gas sale contract. (See e.g. *Sample Contract* at Article 3.1.1) A purchaser may also negotiate a provision to reduce the Maximum Quantities up to 50% with at least two years notice. (See e.g. *Sample Contract* at Article 3.) If a potential purchaser wishes to negotiate for terms that would permit terminating the contract or reducing the Maximum Quantities by more than 50 percent, it should include a proposal for the option. (See e.g. *Sample Contract* at Article 9.4 and the discussion of Option Price above.)

Six months before the production month in which the RIK gas will be delivered, the State will notify the PBU and PTU operators of the percent of royalty gas it nominates for the production month to tender to the buyer. The *Sample Contract*, Article 3, provides an illustration for the buyer to notify the State of its quantity nomination for RIK gas seven months before the production month. The buyer's nomination may not exceed the Maximum Quantities and a reservation fee will be required for the difference in quantity between the Maximum Quantities and the quantity of royalty gas actually purchased.

The *Sample Contract* specifies that the State will reserve 30 percent of its ANS royalty gas in-value. The State has an interest in keeping some of its royalty in-value for two reasons. First, it provides the base price measure used in determining RIK gas prices. Second, the State's interests are best served by retaining the option to sell some of its RIK gas in the future. For these reasons, the State will not sell 100 percent of its royalty gas, and offers should be for a lesser volume.

No Guarantee of Quantity: The State cannot guarantee a certain quantity of gas under an RIK gas sale contract supply. The State can deliver royalty gas only to the extent it receives royalty gas from the lessees. The quantity of royalty gas available to the State may vary and may be interrupted from time to time depending on a variety of factors, including the rate of production from the leases and units. Furthermore, the State may be required to nominate royalty gas as a percentage of its total royalty gas, and not by quantity. Accordingly, prospective buyers must be willing to accept the risk of receiving more or less than the desired quantity at any given time.

Term: RIK proposals must specify the time period of the sales contract. The delivery of RIK gas will not begin until gas is produced for the gas pipeline. Although the State would prefer a contract term that is relatively short, the State understands that the potential buyers may need RIK gas sale contract terms that matches the term of their pipeline transportation commitments. The state will negotiate a term based on the buyer's proposal.

The RIK gas sale contract will be terminated if the Royalty Board or Legislature has not approved the final contract by August 31, 2002, or if an open season does not occur By December 31, 2004, or if an ANS gas pipeline is not in service or royalty gas has not been delivered to the pipeline by July 31, 2012. The State selected these dates to balance the requirements of potential purchasers with the State's requirements to take advantage of alternative opportunities as soon as possible should the pipeline project be delayed.

It is important to note that, while the period of deliveries will be negotiated in the final contract, obligations to pay for price and volume adjustments may extend for months or years after the deliveries.

Source: In drafting the *Sample Contract*, the State assumed that RIK gas would likely come from the PBU and the presently undeveloped PTU and be delivered into an ANS gas pipeline. Estimated total production of gas is 2.5 Bcf per day from the PBU and 1.5 Bcf per day from the PTU, but could be substantially different. The state's royalty share of this production will be approximately 400 mmcf per day. The State cannot guarantee that RIK gas will be available from a specific unit or source.

Under the terms of the *Sample Contract* the State will deliver RIK gas first from the PBU and, if adequate volumes of royalty gas are not available from the PBU, then from the PTU. This allocation will be subject to the 30 percent reservation described above and a mechanism that prorates the volumes of RIK from each unit based on the buyer's monthly nomination. Under this proration each buyer of royalty gas will pay the same Base Price per Mcf calculated from the weighted-average royalty values for royalty in-value. However, the State reserves the right to supply the contract quantity of RIK gas from either or both PBU or PTU or other units, unless otherwise negotiated in the final RIK gas sale contract.

III. DISCUSSION OF SAMPLE CONTRACT TERMS

The final RIK sale contracts negotiated by the State will include contract terms similar to those found in a standard gas sale contract with certain terms to reflect the unique nature of the RIK sale. Because of the uncertainty of the future of a gas pipeline and the need to act quickly, the State reserves the right to negotiate all contract terms with the successful buyers. Below is a discussion of the type of terms the State expects to include in the final RIK gas sale contracts.

The final RIK gas sale contracts and the all commitments of the State and the buyers are contingent on the successful completion of an ANS gas pipeline by 2012.

A. Point of Delivery

The RIK gas sale contract will define the point(s) of delivery as the transfer point where the State receives its royalty gas in-kind from the lessees. Specific points of delivery are not yet known.

B. Field and Conditioning Costs

The RIK gas sale contract will require that the purchaser pay any and all field and conditioning costs chargeable against the State's royalty share of gas subject to the contract.

Field and conditioning costs may vary from lease-to-lease and unit-to-unit. Various lease, unit, and royalty settlement agreements address whether field and conditioning costs, or one or the other, may be charged against the State's royalty share of gas. The State's obligation to pay these costs may depend on whether the State takes its royalty share in kind or in value. In

addition, the RIK purchaser will be effectively bound by any future agreement between the State and lessees as to field and conditioning costs chargeable against the royalty gas sold.

This term is non-negotiable.

C. Payments

The State will bill the buyer each month using its best estimate of price and volume. The State will make adjustments in later months as information about price and volume becomes available.

This term is non-negotiable.

D. Security

The security provision is to protect the State's interests if the buyer defaults on payments, becomes unable to take all of the sale gas it specified under the RIK gas sale contract, or otherwise fails to meet its performance obligations. The State's risk exposure takes at least three forms. First, under the contract the State will bill the buyer for RIK gas the State supplied in the previous month. If the buyer defaults the State may not receive payment for the gas it already supplied. Second, there is the "de-nomination" risk. The State must provide at least six months notice to the lessees to de-nominate RIK and return it to RIV. During this six-month period the State may have to find other buyers for RIK gas the buyer cannot accept or pay for, or the State may have to pay the lessees to take the RIK gas back in-value. Third, if the contract includes Special Commitments, there is the risk that the buyer will fail to meet the commitments. Insofar as the State may have awarded a gas sale contract in part because of the benefits to the state provided by the Special Commitments, the State will regard the buyer's failure to perform those commitments as real damages to the State and may pursue damages in addition to the amount of the security.

The *Sample Contract* illustrates potentially acceptable forms of security: 1) an irrevocable stand-by letter of credit giving the State the right to draw on the letter of credit or present drafts to the issuer at any time through at least six months after the State's final delivery of gas; 2) a security contract between the buyer and a promisor for the direct benefit of the State; and 3) a provision for any special security arrangements offered by the buyer in its RIK proposal and negotiated with the State. Other forms of security may be determined by the commissioner to be adequate to secure the State. The commissioner may require additional security to protect the State's interests.

The requirement to provide security is non-negotiable; however, the security terms may be negotiated to some degree.

E. Default and Termination

The commissioner may suspend or terminate the State's obligations to sell RIK gas or reduce volumes if the buyer fails to do one or more of the following:

- The buyer fails to perform any of its obligations under the contract and fails to cure the non-performance or the non-performance continues for more than 30 days after the buyer has been notified by the State of the non-performance;
- The buyer fails to pay in full any sum of money owed under the contract within two business days after the State gives the buyer notice that payment is due and has not been paid;
- The buyer fails to provide written assurances satisfactory to the State of its intention to perform its obligations under this agreement and provide evidence or assurances of transportation arrangements;
- The buyer fails to comply with all terms of the RIK sale contract to secure payment;
- There is a substantial change in the buyer's financial condition, business operations, property, or ownership that may affect the buyer's ability to perform its obligations under the contract; or
- If any representation or warranty made by the buyer in accordance with the contract is found to have been materially false or incorrect when made.

The buyer is required to notify the State immediately if the buyer is insolvent or unable to pay any of its debt. This automatically terminates the State's obligations to deliver gas. If the buyer defaults, all monetary obligations are immediately due.

If the buyer defaults or the contract is terminated, the State may immediately give notice to the lessees "de-nominating" its RIK. However, the State must provide the lessees with six-months' notice of nomination. Consequently, the buyer may be obligated to continue to take the gas during the notice period if the State chooses not to assume physical possession of the gas, or is unable or unwilling to sell the gas in a distress situation.

If the buyer initiates termination of the contract, the State requires a minimum of six months and ten days written notice of early termination of the contract.

This term is non-negotiable.

F. Successors and Assigns

Neither party to the contract may assign or encumber the agreement without first obtaining the written consent of the other party.

This term is non-negotiable.

G. Interpretation of Terms and Conditions

The State will include a dispute resolution procedure in the RIK gas sale contract. It will permit either the State or the buyer to start the process by providing written notice of a disagreement or dispute to the other party. The State and the buyer are permitted to submit to the commissioner written arguments and evidence supporting their views of the dispute and a proposed resolution. The buyer must agree to be bound by the commissioner's resolution of the dispute if the resolution is reasonable and not arbitrary.

This term is non-negotiable.

G. Other Provisions

The sales contract will contain other standard provisions such as force majeure, buyer and seller warranties, metering, and balancing. To the extent permitted by law and as appropriate to the proposal, a provision for local hire may also be included. Finally, because any contract will be entered into many years before first gas deliveries, a provision will be included to allow a change in terms if necessary to better implement the original intent of the parties.

IV. ANALYSIS OF STATE BENEFITS

To determine whether a sale of the State's Royalty Gas at this time is in the State's best interest, the commissioner considered (1) the economic impacts of the proposed sale to the State; (2) the projected social impacts of the transaction; and (3) the projected positive and negative environmental effects related to the transaction.⁶

The State will always sell its royalty gas as it does royalty oil. When the State keeps its royalty in-value, it "sells" it to the lessees who, in turn, deliver into the market and pay the State the value. When the State sells its royalty in-kind, it becomes a participant in the market where the lessees sell their production. In both instances the State receives the value for its royalty.

Regardless of whether a buyer purchases ANS gas from the State or a producer, its availability may be an incentive to make in-state investments. For example, access to an assured supply of gas from the State might facilitate financing for the buyer or allow the buyer to commit to capacity on an ANS gas pipeline in an open season. By making its ANS royalty gas available at this time the State hopes to encourage such investments and, in so doing, contribute to diversity in the State economy.

At this stage it is not possible to know whom, if anyone, will be successful buyers, or what or where any facilities might be built as a result of a competitive RIK sale. In order to consider the impacts of the proposed sale, DNR contemplated four reasonable scenarios possible for RIK sales:

1. To a buyer who will deliver the gas to markets in the Lower 48;
2. To a facility on the North Slope;
3. To an industrial facility in Fairbanks or another Alaskan community along the pipeline route; and
4. To gas or electric utilities in Alaska.

Three of the scenarios contemplate in-state sales that would likely involve local construction and operation of facilities. These scenarios would have economic, social and environmental effects of their own. But incremental economic, social, and environmental effects, beyond royalty revenues and administrative effects, attributed solely to sale of RIK gas are, with few exceptions, unlikely. However, the RIK sale could accelerate the timing of potential economic benefits.

⁶ See AS 38.05.183(e) and AS 38.06.070(a).

A. Projected Economic Impacts

The RIK gas sale should generate greater royalty revenues and, possibly, stimulate an earlier commercialization of ANS gas. Consider the following scenarios:

Scenario 1: Sales of RIK gas to buyers who will deliver the gas to markets in the Lower 48. A Scenario 1 sale will generate economic benefits to the State in the increase in royalty revenue that results from RIK sales. About 70 percent of the additional royalty revenue will go to the State general fund. The extent of the economic effects will depend on the size of the RIK price premiums offered or cash bonuses received and the nature of their expenditure by the state

Suppose, for example, that current holders of undeveloped oil and gas leases on the North Slope are awarded RIK gas sale contracts and commit to capacity on the pipeline during an open season. These RIK purchasers have an additional incentive to step-up exploration and development of their own gas resources. They would hold reserved pipeline capacity to transport their own new gas production to market as they reduce their gas purchases under the RIK gas sale contract. The principle economic effect would be to accelerate the timing of new jobs in the exploration phase, increased personal incomes from wages, local purchases and contracting, and potentially new gas development. It could also contribute to more vigorous competition and higher bonus bids for oil and gas leases that the State will offer in ANS lease sales in the future.

The RIK sale may affect production of equity gas from the PBU and PTU. If new explorers buy RIK gas and lever the purchases into firm capacity nominations in the open season, the existing resource owners (as pipeline sponsors) could design a larger pipeline to meet throughput requirements. The existing resource owners might be encouraged to produce equity gas earlier and at higher rates because they can produce equity gas to meet their firm transportation commitment instead of shipping RIV gas.

Alternatively, if pipeline capacity is not increased, the existing resource owners may have to reduce their equity production if the new exploration is successful. If the new explorers who have bought RIK gas are successful in gas exploration and begin to produce gas from their newly developed leases, they would reduce their purchases of RIK gas. The RIV gas volumes from the PBU and PTU will increase and displace some equity gas of the existing resource owners. This situation could result in a decrease in the revenues for the existing resource owners and underutilization of the PBU and PTU conditioning plants and other lease investments.

However, existing resource owners have not provided estimates of the potential benefits of early higher rates of equity production and costs of potential future reductions of equity production or pipeline expansion.

Scenario 2: Sales of RIK gas to industrial users on the North Slope. The State's RIK gas will not be offered at a subsidized price and, if the market factors are favorable without a subsidy, other sources of ANS gas can be and have been induced to supply North Slope industrial users. Under

Scenario 2, the economic effects would result from increased royalty revenues of selling the State's royalty in-value.

Scenario 3: Sales to an industrial facility in Fairbanks or other Alaskan community along the pipeline route. The volume of RIK gas expected to be produced for the ANS gas pipeline will probably be insufficient to supply the NGLs needed for a petrochemical plant. Such a development would have to supplement any RIK gas purchase with gas supplied from other ANS producers.

A company's decision to move forward on such a project, like any investor's decision to move forward on a major industrial use of ANS gas, will result from an evaluation of the market fundamentals including gas supply prices, transportation logistics, and the demand for industrial products. As in Scenario 2, a Scenario-3 RIK gas sale to an industrial facility would produce increased royalty revenues to the State. The economic benefits of a petrochemical plant would go beyond royalty revenue receipts. They would include employment opportunities during construction and operation, personal incomes, property tax revenues, corporate income taxes, and the impact through value added through the manufacture of intermediate products such as polyethylene and propane. But these benefits value-added benefits would accrue to the project whether the gas supplying the plant comes from the State's RIK or from a gas producer.

Scenario 4: RIK gas sales for local utility gas and electric power generation. A study conducted by Econ One Research for the department has evaluated the economic feasibility of sales of ANS gas to electric or gas utilities in Alaska.⁷ (See Appendix C.) The pipeline designs promoted by various sponsors in recent months consist of high-pressure, dense-phase (i.e., containing NGLs) pipelines. Gas suitable for space heat or electric generation cannot be removed from the pipeline without lowering pipeline pressure and extracting the NGLs. These costs, combined with the acquisition, transportation, and distribution costs of delivering ANS gas to Alaska customers, suggest that in order to achieve sufficient economies of scale, utility gas supplies will be limited to only the largest concentrations of gas dispositions in Alaska.

If ANS gas can be supplied economically to local gas and power utilities, consumers may benefit from lower energy prices as compared to the price of alternatives energy supplies in the State. If utilities are able to acquire ANS gas for less than the cost of ANS gas in the Lower 48 then this could invite commercial and industrial gas-related investment in Alaska. Current in-state demand for gas in all uses is approximately 227 Bcf per year. Utility gas usage for residential and electric power generation account for about 29 percent of total in-state gas usage. The remainder includes commercial and industrial usage, including LNG exports, ammonia-urea manufacturing, and gas for TAPS pump stations and North Slope field operations. According to Econ One, potential in-state usage of gas could increase by 140 Bcf per year in 2020 due to baseline growth, expanded gas service, new industrial uses, and fuel switching for power generation. This estimate, however, is based on several assumptions:

⁷ Dismukes, David E. et al. 2001. Alaska Natural Gas In-State Demand Study. Prepared on behalf of the Alaska Department of Natural Resources by Econ One Research, Inc., Los Angeles, California and Acadian Consulting Group, Baton Rouge, Louisiana.

- Relative energy prices in the future are consistent with levels observed today;
- The state's regional economy exhibits continued gradual economic expansion at rates comparable with the past five years (about a half percent per year in real dollars);
- In-state access to ANS gas from a high-pressure, dense-phase gas pipeline from the North Slope to Canadian and Lower-48 destinations is not cost prohibitive.

The study concludes that the economics of supplying ANS gas for various in-state uses, including new industrial uses and expansions of current industrial uses, are favorable only if the throughput in a spur pipeline to Southcentral Alaska is high enough to generate needed economies of scale. In order to reach competitive levels of throughput, the spur pipeline would have to serve some of the existing customer base now served by gas reserves in the Cook Inlet Basin as well as potential growth from expanded gas service and new industry applications. Rising gas prices in the Southcentral region may encourage new exploration and development of gas resources in the Cook Inlet but may also jeopardize industrial consumption and LNG exports. Even with rising Southcentral gas prices, ANS gas may not be competitive when the tariff on a spur pipeline linking Fairbanks with Southcentral is added to the cost of ANS gas deliveries to a meter-station tap near Fairbanks.

Natural gas distribution in the City of Fairbanks began in 1998 with LNG imports from gas produced in the Cook Inlet Basin and shipped north by the truckload at delivered, burner-tip prices of about \$7.50 per Mcf in 2001. Total gas usage for residential space heating Fairbanks has increased to about 155 million cubic feet per year in 2001 (0.155 Bcf per year). Various estimates, including the Econ One study indicates that baseline growth plus expanded residential gas service to areas not yet connected in the interior region including Fairbanks could increase gas usage to 2-to-6 Bcf per year by 2020. Conversion of electrical generation for the military bases and the University of Alaska Fairbanks complex could double estimated gas usage by 2020. These estimates are included in the statewide forecast above and build on the same assumption that the cost of gas delivered to interior region applications, including furnace and generator system conversion to natural gas, would be competitive with other energy alternatives.

B. Projected Social Impacts

The analysis of social impacts is similar to the analysis of economic benefits. The proposed RIK sale itself will have no significant or reasonably foreseeable effects on land use, local schools, roads, or other state infrastructure. Social impacts that might occur as a result of RIK gas sales to in-state facilities include:

- Additional employment opportunities while the facilities or pipelines are being built.
- Long-term employment opportunities once the facilities or pipelines are operational.
- Utility gas or electric supplies to towns and villages in interior Alaska.
- An additional tax base to local governments from facilities built in an organized borough or town, such as the North Slope or Fairbanks North Star Boroughs.

C. Projected Environmental Impacts

The sale by itself will have no incremental environmental impact. However, it is conceivable that some environmental impacts could indirectly result from activities or projects developed by the successful buyers. But before a project may commence permits must be obtained and findings must be made. The permit and findings process imposes conditions on allowable impact of projects.

Permits: Depending on the project proposed and the exact location, a combination of permits could be required prior to construction.

DNR, Div. of Mining, Land, and Water Land Use Permit – This permit could be required if a proposed facility is located on state land or crosses state land.

DEC Air Quality control Permit to Operate – The federal Prevention of Significant Deterioration (PSD) program, which is administered by DEC, establishes threshold amounts for the release of byproducts into the atmosphere. Oil and gas exploration and production operations with emissions below predetermined threshold amounts must still comply with state regulations designed to control emissions at these lower levels (18 AAC 50). Activities that exceed predetermined PSD threshold amounts are subject to a more rigorous application and review process. Such activities include the operation of turbines and gas flares.

DEC Wastewater Disposal Permit – Domestic gray water must be disposed of properly at the surface and a permit is required under 18 AAC 72.

Corps of Engineers Wetlands Permit – If a facility is proposed for location in wetlands a permit will be required from the Corps of Engineers. Before a permit may be issued, the Corps will need to complete an environmental assessment and possibly an environmental impact statement under the National Environmental Policy Act.

Alaska Coastal Management Program (ACMP): Alaska has a coastal management program in accordance with the Federal Coastal Zone Management Act of 1972. Alaska's program sets out statewide standards that govern how various uses, activities, resources, and habitats are managed under the ACMP.⁸ It applies generally to lands along Alaska's coast and along some rivers. Parts of the North Slope Borough are within the coastal zone, while Fairbanks is not within coastal zone boundaries.

In addition, communities and boroughs may adopt local management plans. The North Slope Borough has adopted a local coastal management plan (NSBCMP) under the ACMP. Any proposed facilities, including pipelines, must be consistent with both the ACMP and the NSBCMP.

⁸ 6 AAC 80.040 – 150.

Zoning: Both the North Slope Borough and the Fairbanks North Star Borough have developed zoning ordinances.⁹ Any industrial development would be subject to local zoning.

To the extent that RIK gas is sold to in-state utilities and users might displace other fuels such as coal or fuel oil, there may be beneficial impacts on air and other resources.

V. ANALYSIS OF THE PROPOSED RIK GAS SALE

As demonstrated by the proposal and contract terms discussed above, taking a portion of the State's royalty gas in-kind and selling it by competitive sale is in the best interests of the State.

The competitive sale could enhance the State's economic interests through increased revenues without any measurable negative social or environmental impacts. The State will not award an RIK gas sale contract if the sale price is not at least equal to the amount the State would receive if it took its royalty in-value. The competitive process gives the State the opportunity to accept proposals that offer the greatest benefit to the State. And the State can impose contract conditions that protect the State's interest while affording the flexibility necessary to attract serious proposals.

The sale and contract terms do not preclude a purchaser from exporting the royalty gas from the State. At 4 bcf per day, total production of ANS gas exceeds by four-fold future potential in-state domestic and industrial usage. However, using the most optimistic gas demand forecast from the Econ One study and the most pessimistic Cook Inlet gas supply outlook, the State's royalty share by itself will not be sufficient to meet in-state requirements in 2020.¹⁰ Nevertheless, 30 percent of the ANS gas state royalty share reserved in this sale could satisfy baseline utility gas demand growth predicted in the Econ One study for residential and power generation usage. This level of demand will materialize only if ANS gas can be acquired, delivered, and distributed to customers throughout the Southcentral and Interior region at competitive prices.

In determining that the proposed sale is in the best interests of the State, the commissioner also considered the criteria of AS 38.06.070.

1. Revenue needs and fiscal condition of the State: The economic condition of the State is largely dependent on its royalty revenues from oil and gas sales. Supplementing the current royalty revenue sources grows more important each year as production declines in the larger fields on the North Slope. The State can be paid for its royalty gas either in-value by the lessees or in-kind through competitive sales such as the one proposed. Because contract award will depend, in part, on the price premium offered for the RIK gas supply and cash bonus offered for an option to buy RIK gas, revenues from the sale of RIK gas will exceed the in-value alternative.

⁹ The North Slope Borough's zoning ordinances are located under North Slope Borough Ordinances Title 19 and the Fairbanks zoning ordinances are located under Fairbanks Ordinances Title 18.

¹⁰ This shortfall assumes that demand will grow as a result of baseline economic growth, gas utility expansion in the Southcentral and Interior regions, an expansion of the ammonia-urea plant, a new petrochemical plant is built, and oil- and coal-fired power generation in the Interior is replaced by gas. It also assumes that relative prices for gas in remain unchanged and ANS gas is competitive to alternative energy sources.

If the Price Premium offered in this sale is \$0.05 per mcf and the volume sold under the contract is 200 mmcf per day, the State will receive an extra \$3.7 million per year for the RIK gas.

The sale may also enhance competition for oil and gas leases on State lands. As more companies with access to the pipeline compete for leases, bonus bids for these leases can be expected to be higher. The greater diversity of companies undertaking exploration and development on the North Slope and along the pipeline route may contribute to new royalty revenues for the State.

2. Local and regional requirements for petroleum products: In selling its RIK gas the State becomes another seller in the same market where the State's RIV gas is sold. Offering the State's gas at market prices should not adversely affect the market for ANS gas in the State.

3. Desirability of localized capital investment, increased payroll, and secondary development effects: Depending on the commitments that buyers are willing to make, the sale may yield new investments and other economic benefits in addition to the direct revenues to the State.

4. The social impacts of the sale: No incremental social impacts are projected as a result of the RIK gas sale.

5. Additional costs to state and local governments caused by the development related to the proposed sale: No impact is projected on state and local governments. Any gas sold through the proposed RIK sale would otherwise also have been produced and sold at a lower value as RIV gas. No additional construction projects are assured as a result of this sale.

6. Local and regional labor market: The proposed RIK sale, itself, will have no direct effect in state labor markets, but it might affect the timing of development. If projects that have been proposed for use of the State's RIK gas are developed, there will be a beneficial effect on labor markets through construction projects and operational needs.

7. Environmental effects: The RIK sale by itself will have no negative incremental environmental effect.

8. Impacts on existing private commercial enterprises and investment patterns: Local uses of ANS gas could compete with other higher-priced energy supplies. However, the wholesale and retail markets for local gas will have more affect than the proposed sale will on the price and availability of ANS gas for local consumers, commercial and industrial users, and power generators. If the State's RIK gas is sold at lower prices than alternative fuels, existing private enterprises may realize lower costs and output growth. Incremental economic benefits are not assured by an RIK gas sale.

VI. CONCLUSION

Based on the considerations discussed above, the Commissioner has determined that it is in the best interests of the State to solicit purchase offers at this time for a competitive sale of a portion

of the State's royalty share of natural gas that may be produced from Alaska's North Slope upon completion of a natural gas pipeline.

A person affected by this decision may request reconsideration in accordance with 11 AAC 02. Any reconsideration request must be received by **January 15, 2002** and may be mailed or delivered to Pat Pourchot, Commissioner, Department of Natural Resources, 550 W. 7th Ave, Suite 1400, Anchorage, Alaska 99501; faxed to 1-907-269-8918; or sent by electronic mail to dnr_appeals@dnr.state.ak.us. If reconsideration is not requested by the deadline, this decision goes into effect as a final order and decision on January 25, 2002.

Failure of the commissioner to act on a request for reconsideration within 30 days after issuance of this decision is a denial of reconsideration and is a final administrative order and decision for purposes of an appeal to Superior Court. The decision may be appealed to Superior Court within a further 30 days in accordance with the rules of the court, and to the extent permitted by applicable law. An eligible person must first request reconsideration of this decision in accordance with 11 AAC 02 before appealing this decision to Superior Court. A copy of 11 AAC 02 may be obtained from any regional information office of the Department of Natural Resources.

<Signed>
Pat Pourchot, Commissioner

December 26, 2001
Date

Appendix A: Comments on the Preliminary Finding

By the November 30, 2001 deadline for comments listed in the Preliminary Finding, the State had received letters from Ken Thompson, Anadarko Petroleum Corporation, Phillips Alaska, Inc. and BP Exploration (Alaska) Inc. AEC Marketing (USA), Inc. sent a letter and written testimony to the Royalty Board on November 9, 2001. AEC Marketing also sent a letter commenting on the Preliminary Finding received by the department after the November 30, 2001 deadline. Williams Energy Marketing and Trading sent comments on the Preliminary Finding in a letter dated December 6, 2001.

A public hearing was held November 13, 2001 before the Alaska Royalty Oil and Gas Development Advisory Board.

- Anadarko testified in favor of the sale.
- AEC Marketing also in favor of the sale and timing.



AEC MARKETING

3900, 421 - 7th Avenue S.W.
Calgary, Alberta, Canada T2P 4K9
Phone (403) 266-8111
Fax (403) 266-9746
www.aec.ca

November 9, 2001

Alaska Oil and Gas Royalty Development Advisory Board
c/o Alaska Division of Oil and Gas
550 W. 7th Ave., Suite 800
Anchorage, AK 99501

Attention: Mr. Kevin Banks
Petroleum Market Analyst

This letter is in support of the Preliminary Finding and Determination to Sell Alaska North Slope Royalty Gas in a Competitive Sale ("Preliminary Finding") issued on October 29, 2001. AEC strongly advocates the sale of royalty-in-kind gas and the timeline and process set forth within the Preliminary Finding.

We are confident the proposed royalty gas sale is in the State's best interest and that now is opportune time for the State to capture the maximum benefit from their royalty gas. We also believe initiating the royalty-in-kind process and finalizing the awarded gas sales contracts as soon as possible is critical for current and future gas exploration within Alaska.

Attached is AEC's testimony in support of the Preliminary Finding. If you have any questions, please contact Alan Sharp at (403) 261-2560.

Sincerely,

Alan Sharp
Director, Northern Business Development

Hand Delivered - mmc

Alaska Royalty Oil and Gas Development Advisory Board

Alaska North Slope Royalty Gas in a Competitive Sale

Atwood Building, Room 240 at 9:00am

November 13, 2001

Hearing: To discuss the merits and solicit public testimony on the proposed sale and the Preliminary Finding and Determination to Sell Alaska North Slope Royalty Gas in a Competitive Sale ("Preliminary Finding").

Witness: Mr. Alan Sharp, Advisor to AEC Marketing (USA) Inc.

Testimony: Good morning Mr. Chairman and members of the committee. My name is Alan Sharp. I am the Director of Northern Business Development for AEC Marketing and advisor to AEC Marketing (USA) Inc. ("AMUS"). AMUS is an indirect, wholly-owned subsidiary of Alberta Energy Company Ltd. ("AEC"). One of my key responsibilities is to advise AMUS on Alaska natural gas pipeline issues. Such issues include commercialization of Alaska natural gas, which entails access to a pipeline under fair and acceptable terms and conditions.

I would like to start by giving you a brief background on AEC. We are Canada's largest natural gas producer and one of North America's largest independent oil and gas producers. In 2001, our daily production is expected to exceed 370,000 barrels of oil equivalent. Our current daily sales gas production is approximately 1.5 Bcf/d (November 2001 estimate).

AEC is focused on *Growth, Value and Performance* as it builds a Super-Independent oil and gas company. This strategy capitalizes on the world-class assets and high-quality, long-life reserves that AEC has established in its three strong growth platforms - Western Canada, the U.S. Rockies and Ecuador. In 2000, the Company set a target to double production from existing assets within five years.

The Company is also looking to establish additional growth platforms through new venture exploration in Alaska, the Mackenzie Delta, the Gulf of Mexico, Australia, West Africa and Azerbaijan.

Midstream natural gas storage and pipelines assets comprise approximately 20 percent of the Company's asset base and provide a growing source of cash flow. Currently, AEC's enterprise value is approximately US\$9 billion.

In Alaska, AEC's U.S. subsidiary has over 1.1 million net acres in the Central Arctic region of the North Slope (i.e., Foothills of the Brooks Range). We have vast experience in the exploration, development, production and marketing of natural gas and have come to Alaska to explore for new non-associated gas reserves.

1. The first question I would like to address is why we need to establish a royalty gas sales arrangement now.

- The Alaska Gas Producer Pipeline Team ("AGPPT") has informed us that an open season for nominating capacity on an Alaska gas pipeline could occur as early as the first quarter of 2002.
- AEC's U.S. subsidiary and Anadarko are actively exploring in the Foothills of the Brooks Range, however, we will not have proven gas reserves by 2002. Therefore, nominating for firm capacity in the open season is extremely risky from a financial exposure standpoint.
- As you are aware, there are over 30 Tcf of proven gas reserves on the North Slope. Assuming a 4 Bcf/d capacity pipeline, this pipeline would be full for over 20 years. (Note that in the Oct. 2, 2001 testimony to the US Senate Committee on Energy and Natural Resources, Phillips AK Inc. indicated the pipeline would be full for over 30 years). We have a concern that if we do not obtain firm service in the first open season, we may never be able to acquire capacity on the pipeline. Without some assurance concerning pipeline capacity, continued investment in new Alaska gas exploration is unlikely.

- To reduce the risks of capacity nomination and to ensure continued exploration expenditures, Anadarko and AMUS are interested in purchasing state royalty gas to backstop, if needed, any potential nominations for capacity during an open season. We understand that a royalty sales process takes some time and requires legislative approval. We also understand legislative approval is only available from January to May of any given year, restricting the timeframe that a royalty-in-kind sale could be approved.
- We strongly support the State's Preliminary Finding and the timeline for royalty-in-kind gas sales within. Initiating the royalty-in-kind process and finalizing the awarded sales contracts as soon as possible is critical for current and future gas exploration within Alaska.

2. The second question is what benefits do we and the royalty gas sale offer the State.

- We believe that a sale of royalty gas is beneficial to both the state and to companies like ours who are interested in exploring in Alaska for new gas resources. This exploration is a benefit to the State of Alaska and is in addition to the cash bonuses and price premiums as described in the Preliminary Report.
- Our focus is on non-associated gas in the Foothills. If successful, the State will have new incremental proven and developed gas reserves, plus a more stable and higher State royalty revenue (By this, I mean lowering the State's dependence on oil revenue and its associated gas). Non-associated gas also allows the State to consider enhanced oil recovery projects while still maintaining a stable revenue stream.
- As mentioned earlier, the existing proven reserves in Alaska would likely fill a 4 Bcf/d pipeline for 20-30 years. If additional pipeline capacity were not added, this would likely mean no gas exploration in Alaska for 20 years, as new entrants would not be able to obtain access to the pipeline. As for the AGPPT, they would not need to explore for new incremental gas reserves for about 20 years. By providing royalty gas to explorers like us, the State can ensure exploration will continue to take place in areas that would otherwise remain unexplored.
- We believe the State should leverage its gas volumes of tomorrow to support gas exploration projects of today. The State has no risk, as this is a natural hedge. If the pipeline does not proceed, the State would have no obligation to deliver contracted future royalty gas volumes under those circumstances. The benefits are greater exploration and greater revenues, which is one reason why the Preliminary Finding is recommending the royalty gas sale.
- The more players (producers and explorers) on the North Slope, the more competition that will be created. More competition leads to lower costs and higher royalty revenues for the State.
- The royalty gas sale would help counter the dominant market position held by the AGPPT. AGPPT owns practically all of Alaska's proven gas reserves. Thus, they have the power to influence :
 - a. future exploration and development of new gas resources in Alaska, and
 - b. the rates, terms and conditions of pipeline service, whether as owners of the proposed Alaska gas pipeline or as anchor-shippers.
- More players likely means more jobs for Alaskans. The money we spend exploring and, if successful, developing the Foothills will have a positive multiplier effect on the economy.
- More players will likely contribute to the earlier commercialization of Alaska gas and the successful completion of the pipeline to Canadian and Lower 48 markets.
- We do not require all of the State's royalty gas. The remaining royalty gas could be used for future in-State use and for establishing a meaningful royalty-in-value price.
- AEC is Canada's largest gas producer. One of our core competencies is marketing natural gas in Canada and its interconnected Lower 48 markets. By teaming with AEC, the State will have one of Canada's best producer/marketers working with them. In 2000, AEC had the highest netback gas price compared to the top 23 Canadian producer/marketing companies.
- If our exploration efforts are successful, we will not need to purchase the State's royalty gas. The State will then be free to re-market the royalty gas to other parties, while receiving all the same benefits mentioned above.

3. The third question is do we have any specific comments on the terms laid out in the Preliminary Finding.

- Since the pipeline has not been built yet and actual gas sales will not occur for sometime in the future, we believe the State should leave as many terms and conditions open as possible for the Bidder. This will allow for maximum creativity and innovation. This should also maximize the potential value available to the State.
- We believe the proposed royalty gas sale is in the State's best interest and strongly support the Preliminary Finding. Now is opportune time for the State to capture the maximum benefit from its royalty gas.



2001 NOV 16 PM 3 19

November 12, 2001

Alaska Oil and Gas Royalty Development Advisory Board
c/o Alaska Division of Oil and Gas
550 W. 7th Ave, Suite 800
Anchorage, AK 99501
Attn: Mr. Kevin Banks

Dear Royalty Board:

This letter is being sent in support of the Preliminary Finding and Determination for a Competitive Sale of Alaska North Slope Royalty Gas ("Preliminary Finding") issued on October 29, 2001. Anadarko is a strong advocate of the State's efforts to solicit bids for the State's Royalty gas in accordance with the timeline set forth in the Preliminary Finding. The royalty in-kind ("RIK") bid process timing is critical to current, future, and continued natural gas exploration within the State of Alaska.

Securing access to the proposed natural gas pipeline from the North Slope is a necessity for the continued exploration for natural gas within the State of Alaska. We believe that the gas pipeline capacity will be fully subscribed at the outset. Therefore, failure to secure firm transportation now could result in Anadarko's prospective gas discoveries being stranded without any means to produce and sell the gas. However, without proven gas reserves it will be extremely risky for exploration companies, such as Anadarko, to commit to firm transportation services on the gas pipeline. Firm transportation services entail substantial monthly demand charges that must be paid regardless of whether or not the shipper tenders gas volumes to the pipeline. We anticipate that the demand charges associated with the minimum economic field size in the Foothills region will likely be on the order of \$180 million per annum.

A RIK bid process would allow an opportunity for an exploration company to purchase the State's royalty gas in conjunction with bidding for firm transportation on the future natural gas pipeline. The RIK bid process timing is critical inasmuch as the Alaska Gas Producers Pipeline Team ("AGPPT") that is studying the natural gas pipeline feasibility has publicly stated that an open season for securing capacity on the pipeline could occur in the first or second quarter of 2002.

Conducting this RIK bid process at this point in time capitalizes upon the substantial current interest in the State's royalty gas from a number of diverse industry players. Since firm capacity is expected to be required to market North Slope natural gas and given the expectation of an early 2002 open season, it is expected that now is the optimal time for the State to secure maximum value for its royalty gas. With numerous expressions of interest in the State's royalty gas, it is expected that the competition for the State's royalty gas will be substantial.

In addition, the RIK bid process creates an opportunity for the State to capture real economic value for its royalty gas volumes years before the State will actually have royalty gas volumes available to sell. The gas pipeline needed to market North Slope gas reserves is not likely to be constructed and placed in service until the 2008 - 2010 timeframe.

Given the Preliminary Finding's requirement for a minimum cash bonus and/or cash option payments, in all likelihood the State will realize some form of substantial compensation for its royalty gas volumes some seven (7) to nine (9) years in advance of production and sales. In addition, certain bid structures may entail commitments to in-state investments as outlined in the Preliminary Finding. Such investments would yield substantial economic benefits to the State in terms of incremental investments, increased tax revenue, new employment creation, and similar socioeconomic benefits.

Lastly, given the basic premise and mandate that any winning bid must yield the State a royalty price of not less than the price it would have otherwise received had it sold the gas as royalty in value ("RIV"), there appears to be absolutely no downside to this initiative by the Department of Natural Resources. By definition and structure of the Preliminary Finding, the State will be revenue neutral at worst, but is mostly likely to generate a substantial incremental value to the State along with acceleration of values and benefits vis-a-vis the RIV option. The economic benefits expected from this RIK bid process will accrue to the State in the form of increased State revenues, employment gains, and potential improvements in the standard of living for Alaskan residents.

Holding this bid process now is both appropriate and critical in terms of optimizing and capitalizing upon the opportunities and competitiveness for the State's royalty gas. A timely process will preserve the maximum number of options for the use of State royalty gas, it will help the State better understand the possible uses for its gas, and as has been described above, it is critical to current, future, and continued Alaska natural gas exploration. As a company keenly interested in bidding for the State's RIK gas we appreciate this opportunity to support the process and provide comments. We are confident that this arrangement will provide significant benefits to and be in the best interest of the State of Alaska.

Respectfully yours,

A handwritten signature in dark ink, appearing to read 'D. D. Anderson', followed by a horizontal line.

David D. Anderson
Manager, International Commercial Development

Kevin Banks

From: Ken Thompson [ken@pacrimldr.com]
Sent: Monday, November 19, 2001 2:26 PM
To: krb@dnr.state.ak.us
Cc: Mike Navarre; Ken Freeman; Bonnie Robson
Subject: My Public Comments re; RIK Sale

Thank you for allowing the public to comment on the "Preliminary Finding and Determination for a Competitive Sale of Alaska North Slope Royalty Gas". Below are my personal comments regarding the bidding and potential sale of the State's "royalty in kind" volumes of natural gas from the North Slope.

1) This process, the first of its kind for North Slope RIK gas in Alaska, is being accelerated primarily based on "speculation" that the major producers may hold an open season for nominations in the first quarter, 2002. I suggest a letter from the State be mailed immediately to the three major North Slope producers with a copy to FERC asking these three companies to let the State know by mid-December if an open season is indeed planned for the first quarter, 2002, or not. Also asking this of the new Foothills Pipeline consortium would be wise, in my opinion. While the producers may not tell the State, having documentation either way that the Producers were giving - or not giving - the State adequate real notice would be advantageous to have.

2) The current DNR commissioned study underway by Econ1 regarding the current and forecasted supply/demand for natural gas within the state should be completed and analyzed first before the step of "Publish Final Finding and Invitation to Bid". This may mean that the date of December 12 for the "Publish Final Finding" be delayed some. With analysis of the details in the Econ1 study, the state should assess what portion of the royalty gas must be held off the bid table, or bid but specified for instate use, before the "Final Finding" is mailed. While the "Preliminary Finding" says the state is allowed to keep gas for instate use and that the state will allow only a portion of RIK gas to be bid on, I think it is very important to be more exact. For example, for energy security within the state, it is my opinion that a volume of state RIK gas deliverability from the North Slope be held for replacement of the natural gas shortfall in residential and commercial use from the Cook Inlet. The State should not forecast exploration success in the Cook Inlet to replace this 2006-2008 gas deliverability shortfall which you're aware of, but should be able to fully supply the Anchorage and Cook Inlet increasing gas needs from the North Slope RIK gas or certainly plan to if needed. Considering this, the amount of RIK gas that can be bid on may be less than 250 MMCFD of the total 500 MMCFD if a gross sale is 4 BCFD.

2) For the reason mentioned above and to allow for flexibility for additional bidding packages of RIK gas, it may be wise in this "first pass" of bidding in January, 2002, that no more than 100-250 MMCFD be allowed in this initial bidding package. Bidding in smaller packages is also advantageous in that the State should not want a small gas explorer or producer on the North Slope interested in securing pipeline capacity to "corner" all the available RIK bid capacity or else other smaller explorers would be disadvantaged.

3) I would also suggest with future uncertainty in Cook Inlet gas supply post 2010 that the term of this first bid package be no more than 5 years for the 100-250 MMCFD.

4) If this effort proceeds to bidding and two or more acceptable bids are obtained, the State might choose to accept two bids instead of one to create more future competition for gas marketing, keeping various players interested and involved.

5) It would be advantageous for the State to specify in the "Final Finding" that a North Slope netback wellhead price be presented in a bid for certain volumes. If all bids are quoted as a Lower 48 hub price minus transportation, this still leaves speculation and uncertainty to the netback wellhead price as pipeline tariffs are not yet known. However, if a bidder would step out, take the lead and risk by bidding a netback wellhead price that is acceptable, this would be very significant for Alaska, in my opinion. Such an acceptable absolute price would cross for the first time in Alaska history the "reasonable price" stipulation in the North Slope leases, triggering Producers to also have to consider selling at this price or be in violation of lease terms. This could be

leveraging as these Producers make decisions next year to sell their gas or not.

6) It should be clear that the natural gas liquids in the RIK gas should be separately bid and sold separately based on liquids prices versus a BTU adjusted price.

Please feel free to reply by e-mail or to phone me at 770-1600 if you have questions of me regarding these comments. Thanks again for the chance to provide input.

Sincerely, Ken Thompson
(Past President of ARCO Alaska, Inc. (retired) and currently President, Pacific Rim Leadership Development, LLC)

11/20/2001

November 27, 2001

2001 NOV 28 AM 

Division of Oil and Gas
550 W. 7th Ave, Suite 800
Anchorage, AK 99501
Attn: Mr. Kevin Banks, Petroleum Market Analyst

Re: Preliminary Finding and Determination for a
Competitive Sale of Alaskan North Slope Royalty Gas

Dear Mr. Banks,

In accordance with the provisions of the captioned October 29, 2001 Preliminary Finding, Anadarko Petroleum Corporation submits the following comments for the State of Alaska Department of Natural Resources' and the Alaska Oil and Gas Royalty Board's consideration in the preparation of the "Final Finding" and the related "Invitation to Bid". We would also like to take this opportunity to reiterate our support for this royalty in-kind sales process as set forth in our letter of November 12, 2001 (copy attached).

Although not specified in our November 12 letter of support, we believe that the present is the optimal time for the State to hold this competitive royalty gas sale due in large part to the significant difference between oil pipeline access mechanics and natural gas pipeline access procedures.

Oil pipelines falling under Federal regulations operate as "common carriers" by which all parties seeking transportation are afforded access on a *pro rata* basis. However, natural gas pipelines covered by Federal jurisdiction function as "contract carriage" pipelines. Contract carriage pipelines contract out capacity to potential shippers for fixed terms. Shippers can secure capacity on a "firm" basis meaning such capacity is exclusively available to such shippers. If the pipeline contracts all of its effective capacity under "firm" arrangements, no capacity would be available to subsequent shippers seeking capacity.

We anticipate that the proposed Alaskan gas pipeline serving the North Slope will be fully subscribed with firm service shippers during the open season process. Once all of the pipeline's capacity is let as the firm service, the universe of practical potential State royalty gas purchasers will be fixed to the limited number of shippers successfully securing such firm transportation capacity.

Therefore, in order to ensure that the maximum number of parties compete for the State's royalty gas and thereby ensuring the most attractive bids, the State is correct in proceeding with this bid process before the pipeline open season. After the open season and probable allocation of all of the pipeline capacity on a firm basis, there will likely be fewer potential bidders for the State's royalty gas.

Our questions and comments related to the Preliminary Finding are as follows:

1. Quantity:

Section I. C. on page 4 of the Preliminary Finding indicates that the "Invitation to Bid" will specify the quantity of gas offered for sale. In order to retain the maximum creativity of the potential proposals in response to the Invitation to Bid, we suggest that the State not limit the quantity of royalty gas to be made available, at least not at this early stage of the process. It is further suggested that if any quantity limit is imposed, that such limit be set at the absolute highest volume reasonably acceptable to the State.

2. Term:

As with quantity above, we believe that leaving the term unspecified in the "Invitation to Bid" will allow for more creativity in the potential bids. However, Section II.C. in the Preliminary Finding lends some confusion as to the length of an acceptable term. Section II.C. references a preference for a relatively short term, yet indicates that a term commensurate with the term of the firm transportation may be acceptable. We believe that it would be mutually beneficial to provide greater guidance as to an acceptable term length in the Final Finding and the Invitation to Bid. However, we recommend that an absolute term maximum not be set out in the Invitation to Bid as it may reduce bid creativity.

3. Delivery Point:

Section II.C. in the Preliminary Finding indicates that the delivery point will be defined in the Invitation to Bid. Section III.A. of the Preliminary Finding indicates that there are a number of generic locations that could be established for the Point of Delivery. The selection of the Point of Delivery is a critical matter and it may be more appropriate to defer a final determination of the Point of Delivery until negotiation of the definitive gas purchase and sales agreement following bid award.

It is anticipated that the natural gas subject to this bid process will require conditioning for the extraction of diluents; specifically CO₂. As such, it may be better for the State to secure conditioning services for the royalty gas prior to delivery to the purchaser, as the State will likely have more leverage than the buyer in negotiating fair and reasonable conditioning fees.

4. **Proposed RIK Gas Supply Contract:**

Section I.C. indicates that an RIK gas supply contract will accompany the Invitation to Bid. We recommend that the Final Finding and Invitation to Bid clarify that the subject contract will be a basis for contract negotiations and not non-negotiable. Also, in an effort to shorten the fairly substantial time required to finalize this bid process, we would recommend that the subject contract be tendered to potential bidders as soon as practicable in order that constructive comments may be provided by potential bidders.

5. **Allocations of RIK Volumes:**

The next to last paragraph in Section I.C. leaves open the potential for multiple awards of RIK gas volumes. We would like to take this opportunity to observe that for a number of bidders, there is a minimum quantity of RIK gas required in order to satisfy the bidders' objectives for the RIK gas. For some bidders, such as ourselves, the minimum quantity is quite substantial. We would caution against the inclination to make multiple awards in an effort to appease numerous bidding parties at the risk of undermining the needs of legitimate bidders requiring large quantities to fulfill their needs.

Given our concern as to minimum volumetric thresholds, we request that the Final Finding and Invitation to Bid contain a provision that allows a successful bidder to withdraw its bid if it is awarded a quantity substantial less than the quantity bid for.

6. **Propose No Bidder-Initiated Contact After Bid Opening:**

Given the fact that the terms of all bids will be publicly announced at the "Bid Opening", we recommend that the Final Finding and Invitation to Bid expressly state that no bidder may initiate contact with the Division of Oil and Gas or the Alaska Oil and Gas Royalty Board after bids are revealed at the Bid Opening. We are concerned that absent such a pronouncement, there will be substantial temptation for bidders to enhance their bids based upon the information disclosed by competing bids revealed at the Bid Opening.

7. **Minimum Cash Bonus Bid:**

It is unclear whether this bonus is only assessed against the winning bidder, or whether this is a non-refundable payment due from all bidders as a prerequisite to bidding. This point should be clarified in the Final Finding and Invitation to Bid. Our preference would be that such payments would be refunded unless the bidding party is awarded RIK gas purchases.

8. Base Price Determination:

We suggest that the Final Finding and Invitation to Bid clarify that the RIK gas price paid will not be used in the determination of the RIV gas price. Per Section II.A. of the Preliminary Finding, the RIV gas price is computed based upon the higher of a number of valuation criterion, including the prices received by producers in the field.

By definition, the RIK price will be higher than the RIV price inasmuch as the RIK price will include a premium price added to the RIV Base Price. This creates a circular process wherein the RIK premium price could be factored into the RIV price thereby escalating the RIV and RIK prices without end.

This circular deficiency also arises if one or more of the dominant North Slope gas producers is awarded purchase of the State's RIK volumes. The Base Price for purposes of bidding for the RIK gas is the weighted average RIV price resulting from the sale of North Slope gas. The three largest North Slope gas producers hold over 90% of the proven gas reserves on the Slope. As such, their respective gas sales prices will be prominent in the determination of the RIV sourced Base Price. If one or more of the dominant North Slope gas producers is awarded RIK gas purchases, there could be incentive for that party to manipulate the RIV price in order to minimize the RIK Base Price.

9. Base Price Determination Intent:

Section II.A of the Preliminary Finding contains a discussion of the Base Price determination and in particular the "netback" nature of determining the RIV price. We believe that it would be mutually beneficial to incorporate such a discussion in the Final Finding as well. In fact, we believe that further clarification in the Final Finding, Invitation to Bid, and draft gas supply contract could serve to reduce ambiguity and potential dispute as to the intended determination of the RIV price.

Inasmuch as the RIV price represents the Base Price for RIK pricing, accurate understanding and application of the RIV price is of paramount importance. Any further explanation and/or language that could serve to reduce some of the uncertainty in the determination of the RIV price would serve all interested parties well.

10. Limitation on Base Price Redetermination:

Section II.A of the Preliminary Finding addresses the fact that the RIK Base Price may be subject to modification through audit and dispute resolution for years. In order to limit some of the risk associated with the uncertainty of and administration of the RIV Base Price, we request that the Department of Natural Resources and the Alaska Oil and Gas Royalty Board seriously consider adopting a reasonable statute of limitations for adjustment of the RIV price to be

used as the Base Price for RIK gas pricing. We would suggest a two-year audit cutoff and limit any adjustments beyond the two-year audit constraint to those adjustments arising out of resolution of audit claims which occurred within the two-year audit cycle.

11. In-State Investment Performance Obligations:

The last paragraph in Section II.B. of the Preliminary Finding outlines the potential remedies for the State in the event a bidder fails to carry out in-State investments contained within the bidder's RIK purchase proposal. Given the fact that in-State investments could be given material weighting in the evaluation of bids, we recommend that the Final Finding and Invitation to Bid documents adopt one or more of the more punitive recourses set out in the Preliminary finding.

In particular, there would not appear to be much downside risk to embellishing and/or renegeing on in-State investment elements of one's bid if the only consequence for failure to perform such investments was a cancellation of the sales contract, or a reduction in sales volumes.

12. Delivery Quantity:

Section II.C. of the Preliminary Finding states that the prospective buyer must be willing to accept the risk of receiving more or less than the desired quantity. We suggest that this concept be softened somewhat in the Final Finding and Invitation to Bid documents. In the event the State's RIK volumes exceed the expected volumes, the buyer may be operationally precluded from purchasing the excess volumes if such volumes exceed the buyer's firm transportation capacity and no interruptible transportation service is available on the pipeline at the time.

We would suggest that the Final Finding, Invitation to Bid, and draft gas supply contract address this situation such that the buyer would be under a best efforts obligation to purchase such excess volumes.

13. RIK Supply Source:

The last sentence of Section II.C. affords the State the right to supply the contract quantity of RIK gas from either or both the Prudhoe Bay Unit and the Point Thomson Unit. Given the potential differences between the handling of Field Costs between these units, such unlimited discretion could be materially detrimental to the buyer.

It is our understanding that the purchaser will have to bear Field Costs for some Point Thomson Unit volumes attributable to Form DL-1 leases. If we understand the issue correctly, if the State receives royalty in-value from the

subject Point Thomson leases, the State does not have to bear Field Costs. If, however, the State takes its royalty volumes attributable to these leases in-kind, the State must bear the associated Field Costs.

We would suggest that unless and until such time as the State's total RIK volumes reach a volumetric level requiring the taking of gas from such leases, it would be in both the State's and the purchaser's best interest to preferentially take RIK volumes from those leases not affected by this Field Cost issue.

We would suggest that the Final Finding, Invitation to Bid, and draft gas supply contract address this situation such that, to the extent possible, RIK volumes shall first be sourced from available State RIK volumes other than those attributable to DL-1 leases within the Point Thomson Unit. If, however, the total State RIK quantities being sold to all purchasers requires the taking of volumes from Point Thomson Unit DL-1 leases, then such more costly Point Thomson Unit DL-1 lease RIK volumes shall be allocated to all RIK gas purchasers on a *pro rata* basis.

For instance, if the PTU DL-1 leases represent five percent (5%) of the total available State North Slope RIK gas volumes, then five percent (5%) of the RIK gas allocated to the purchasers should be attributable to PTU DL-1 lease gas.

14. Conditions Precedent:

We would suggest that the Final Finding, Invitation to Bid, and draft gas supply contract contain the added condition precedent that if no open season has occurred prior to April 30, 2005, either buyer or seller may terminate the contract and commitments made by the respective parties.

In addition, given the real potential for substantial delays in the construction of this pipeline that may be well beyond the reasonable control of the State and buyer, such as an inability to secure rights-of-way across First Nations lands in Canada, we would suggest that the 2011 pipeline completion stipulation be revised along the lines of:

"Either party may terminate the contract and shall be under no further obligation to the other party in the event that an ANS gas pipeline has not been placed in-service by December 31, 2011. Provided, however, if buyer has secured firm transportation service on the pipeline for RIK gas purchases and is unable to terminate its firm transportation obligations with the pipeline despite its best efforts to do so, the State agrees that it will defer its right to terminate the RIK gas purchase contract for a two year period ending December 31, 2013."

15. Field and Conditioning Costs:

We suggest that the language set out in Section III.B should be revised consistent with our comment No. 3 above concerning the location of the Point of Delivery. As we understand the Field Costs situation, through various settlement agreements, the State bears its proportionate share of Field Costs as to royalty gas volumes from the Prudhoe Bay Unit regardless of whether the State takes its gas in-kind or in-value. However, under certain leases within the Point Thomson Unit, the State does not bear its proportionate share of Field Costs as to royalty taken in-value, but does bear these costs for volumes taken in-kind.

We recognize the State's requirement that any RIK sales must yield the State a value equal to or greater than the value the State could have otherwise received through sales of royalty gas in-value. We further recognize that any RIK gas sold which bears a Field Cost that the State would not have otherwise incurred must be borne by the buyer. However, we believe clarification of this point is warranted in the Final Finding, Invitation to Bid, and draft gas supply contract.

However, we are unclear as to whether or not the State bears its proportionate share of gas conditioning costs under the terms of the leases held by the unit owners. If the costs associated with gas conditioning do not follow the same logic and process set out above for Field Costs, then the appropriate handling of these costs need to be addressed in the Final Finding, Invitation to Bid, and draft gas supply contract.

The handling of Field and Conditioning Costs is a complex matter and is interrelated with the established Point of Delivery and the disbursement of proceeds procedures. We suggest that this complex issue be better developed in the Final Finding, Invitation to Bid, and draft gas supply contract.

At a minimum, we believe that the Final Finding, Invitation to Bid, and draft gas supply contract should clearly state that the Base Price derived from the weighted average RIV price is intended to reflect the netback market price for North Slope natural gas sales, after deduction of all actual pipeline tariffs, treating and conditioning fees, and Field Costs that are normally borne by the State in a royalty in-value sale. The buyer shall only be responsible for keeping the State whole as to Field Costs related to quantities of gas attributable to leases that would not bear such costs in a royalty in-value mode.

16. Default Notice and Termination:

The timing set forth in the second bullet point in Section III.E. of the Preliminary Finding is unreasonably restrictive. In all likelihood, the winning bidder under this process will be a large company. Given the substantial segregation of duties within large organizations it is unreasonable to grant the

State the right to suspend performance or terminate the contract if the buyer fails to make full payment within one day's notice that payment is past due.

We strongly recommend that the Final Finding, Invitation to Bid, and draft gas supply contract address this issue with a more reasonable default timeframe. In a large organization it is very likely that a default notice may not reach the attention of levels of management empowered to facilitate such payments within the one day timeframe set forth in the Preliminary Finding.

17. Interpretation of Terms and Conditions:

We request that the language contained in Section III.G. in the Preliminary Finding addressing dispute resolution be modified in the Final Finding, Invitation to Bid, and draft gas supply contract to clarify that the Commissioner's finding may be appealed in court. As currently drafted, it appears that the Commissioner's finding is final. Inasmuch as the Commissioner serves a critical role in the negotiation and application of the RIK gas sales contract in his/her capacity as a representative for the State, his or her findings may fall short of a disinterested, objective assessment of any dispute under the terms of the contract.

18. Other Provisions – Preservation of Intent:

The last sentence in Section III.G. of the Preliminary Finding indicates that the gas sales and purchase contract will contain a provision to facilitate modifications to the contract in order to ensure preservation of the parties' intent should changes in the market occur during the course of the contract. We support such a clause provided that the language is constructed to the mutual satisfaction of both the State and the purchaser.

The State should recognize that any RIK purchaser will be required to secure transportation services for the RIK purchase volumes and such transportation services are likely to carry substantial demand charges (ship-or-pay provisions). Therefore, it is imperative that the purchaser be afforded as much contract certainty as is reasonably possible. We strongly suggest that at a minimum the application of any such "intent preservation" provision be limited to market changes that have a material detrimental impact on the affected party.

19. Section IV. - Analysis of State Benefits:

We recommend that the next to last sentence on page 12 of this Section of the Preliminary Finding be clarified in the Final Finding. Our concern is that the mere purchase of the RIK gas may provide incentive for the purchaser to make in-State investments that it might not otherwise make. We believe the intent of the sentence in question is to state that such in-State investments cannot be induced by subsidization through below-market RIK sales terms. In fact, the

preceding sentence makes specific reference to subsidization prohibitions. We simply request that the Final Finding clarify that an RIK sale alone, which results in incremental in-State investments is not contrary to State regulations so long as such RIK sales terms are not below-market or subsidized.

We thank you in advance for your consideration of these comments as you move forward in the drafting of the Final Order, the Invitation to Bid, and the drafting of the pro forma gas purchase and sales contract. Should you have any questions concerning these comments, please feel free to contact me at 832-636-7139, or Angie Kelly at 832-636-7196.

Respectfully yours,

A handwritten signature in black ink, appearing to read "David D. Anderson", followed by a horizontal line.

David D. Anderson
Manager, International Commercial Development



PHILLIPS Alaska, Inc.
A Subsidiary of PHILLIPS PETROLEUM COMPANY

P. O. BOX 100360
ANCHORAGE, ALASKA 99510-0360
Phone (907) 265-6517

Joseph P. Marushack
Vice President, ANS Gas Commercialization

November 30, 2001

Mr. Kevin Banks, Petroleum Analyst
Department of Natural Resources, Division of Oil and Gas
550 W. 7th Ave. Suite 800
Anchorage, AK 995801

RE: Preliminary Finding and Determination for a Competitive Sale of Alaska North Slope Royalty Gas, dated October 29, 2001.

Dear Mr. Banks:

On behalf of Phillips, thank you for the opportunity to comment on the subject preliminary finding. Our comments fall into two areas: timing of the process and impact to owners of known resources.

Relative to timing, it appears to us that the royalty sale activity does not need to be so quickly paced. The preliminary finding and DNR staff comments at the November 13, 2001 public meeting both indicate that the timing of the RIK sale process is being driven by an expectation that the work of the AGPPT could result in an open season as early as January, 2002. As we have frequently indicated, the Project Team has been working to develop an economic project, obtain Federal enabling regulatory legislation and to progress a framework for fiscal clarity within Alaska. Although progress is being made in Washington, DC, the federal legislation is unlikely to be available before sometime later in 2002. Therefore, we do not foresee holding an open season during 1Q 2002. In fact, it is pre-mature to make any near-term estimates on when an open season might occur. Consequently, we suggest that any RIK sale process be deferred pending greater definition in this area.

Next, we recommend that the findings be expanded to fully consider additional potential impacts.

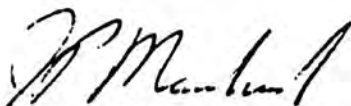
One of the stated reasons for the royalty gas sale is to provide RIK gas as a "back-stop" to gas production that companies with unexplored leases on the North Slope hope to develop. This means that if an RIK purchaser were to exercise its option to stop buying RIK gas, the existing resource owners would suffer a reduction in delivered volumes of equity gas and likely under-utilization of the gas treatment plant and any other on-lease investments made expressly for gas sales. It is the known resource owners who must make the base, long-term, throughput commitments for any pipeline project to be developed. As such our net volume must be known and not subject to reduction. The State's RIK proposal clearly seeks to transfer the benefits of those long-term commitments to new participants without transferring the associated risk. Our

fundamental concern is that this will further burden the economics of the overall project and add uncertainty at a time when we have yet to realize an economic way forward.

We believe that fair and unbiased capacity allocation and expansion procedures, as achieved through the FERC regulatory process, will assure that all gas producers, both present resource owners and potential explorers, have adequate access to transportation capacity. While the backbone of the project will be for existing reserves to be developed, the ability to expand capacity has always been a priority for Phillips and in the joint producer work effort. Creation of and access to such expansion capacity should better occur under an open and non-discriminatory basis as new sources of supply are identified and the markets demand.

Thank you for the opportunity to present these comments on the subject finding. If you desire, we would be happy to follow up these general comments with additional information. If you have any questions or concerns, please do not hesitate to contact me directly at (907) 265-6517.

Sincerely,



Joseph P. Marushack
Vice President, ANS Gas Commercialization
Phillips Alaska, Inc.

bp



BP Exploration (Alaska) Inc.
900 East Benson Boulevard
P.O. Box 186612
Anchorage, Alaska 99518-8612
(907) 581-5111

November 30, 2001

Mr. Kevin Banks, Petroleum Analyst
Department of Natural Resources, Division of Oil and Gas
550 W. 7th Ave. Suite 800
Anchorage, AK 995801

RE: Preliminary Finding and Determination for a Competitive Sale of Alaska North Slope Royalty Gas, dated October 29, 2001.

Dear Mr. Banks:

On behalf of both BP Exploration (Alaska) Inc. and our Gas & Power group, I would like to thank you for the opportunity to provide both written and verbal comments on the subject preliminary finding. I hope you and the other DNR staff found our meeting on November 14 beneficial.

Timing

The preliminary finding as well as comments at our meeting both indicate that the timing of this proposed RIK sale is being driven by the perception that the Alaska Gas Producers Pipeline Team may hold an "open season" for pipeline capacity as early as January 2002. We do not foresee any possibility of holding an open season during 1Q 2002 and apologize for any miscommunication in this regard. Indeed it is presently unlikely that an open season will be held anytime during 2002 unless some important government actions are progressed.

As we have stated previously, for a gas pipeline to attract investment, there must be an economic project and there must be a predictable and viable government framework in place to support investment. Both federal regulatory legislation and clarity around State tax and royalty are important pieces of this government framework.

AGPPT is currently working diligently to engineer and design a modern day gas pipeline with competitive tariffs to market, however to date costs are trending above where they need to be. Progress is being made in Washington DC on the enabling regulatory legislation, but current prognosis suggests it is unlikely that it will be available before sometime later in 2002. Finally, much work remains on progressing a framework for fiscal certainty with the State of Alaska and this proposed RIK sale actually highlights the uncertainty of the current fiscal framework under which we must evaluate the economics of this project.

Impact on the Economic Viability of Pipeline Project

As currently structured, this RIK gas sale is being pursued to provide a free capacity access option to parties without proven gas reserves. If the sale proceeds with an option to switch between RIK and RIV on short notice, overall project economics would be materially burdened by the uncertainty in equity gas sales volumes of the known resource owners who will need to make binding contractual commitments to ship gas for many years. This burden on an already marginal project is a clear step in the wrong direction. Such a burden would make it unlikely that producers would subscribe to any open season unless financially compensated for the burden.

For example, an RIK purchaser could use its purchased gas as a backstop for making a firm transportation commitment on a gas line. The balance of the FT commitments to get the line built would be made by the known resource owners. Should an RIK purchaser discover its own gas resources, it could cancel its purchase contract with the state and substitute its own gas into its FT commitment. The State's gas would then revert back to the known resource owners in the form of RIV gas thus reducing the amount of equity gas that the resource owners could export via their own fixed-volume of FT commitment. This reduction would result in a loss of revenue to the known resource owners as well as result in the probable under-utilization of asset investments made at the lease level.

The State's RIK proposal clearly seeks to transfer benefits from long term investors to new participants without transferring the risk associated with the massive investment that will be required to make any gas pipeline a reality. Such subsidies at the expense of those who will ultimately underwrite any new build pipeline are both unfair and, more importantly, reduce the chances of developing an economically viable project.

We believe that fair and unbiased capacity allocation and expansion procedures already exist through the FERC regulatory processes. These processes will be sufficient to assure that all gas producers, both present resource owners and potential explorers, have adequate access to transportation capacity. If the State has reservations in this regard, we are prepared to discuss this further or to meet jointly with FERC officials to gain a full understanding of how FERC ensures fair and consistent rules of access are developed and administered.

Efforts to fix a problem that doesn't exist with economically burdensome solutions cannot be in the best interest of the State, especially if those solutions could cause a gas pipeline project not to proceed at all.

We and AGPPT have discussed this matter with the State previously and we believe our discussions on this matter have been consistent. However, we regret if we have not been clear and hope this letter will help provide additional clarity.

We respectfully request that the state refrain from taking steps that will further jeopardize the commercial viability of a pipeline project.

Page 3

Prospective Bidding

The above discussion should not be construed to mean that BP is in anyway opposed to the State marketing its royalty gas. Indeed, in the event the State wishes to market its gas in a manner consistent with fair market principles and consistent with the long-term firm transportation commitments necessary, BP could provide a fully competitive offer.

In many respects, a properly structured RIK sale could actually address part of industry's concerns around fiscal stability. Clear and transparent pricing for royalty gas would be an important step towards the fiscal clarity industry is seeking.

We would be happy to follow up these general comments with additional information and discussion at any time. Please do not hesitate to contact me directly at (907) 564-5553.

Sincerely,



Charles J. Coulson
Commercial Manager - Alaska Gas
BP Exploration (Alaska) Inc.

cc: David Welch
Ken Konrad
Pat Pourchot
Ken Freeman



AEC MARKETING (USA) INC.

3700, 707 -8th Avenue S.W.
Calgary, Alberta, Canada T2P 1H5
Phone (403) 261-2560
Fax (403) 290-8588
<http://www.aec.ca>

*rec'd via email on
12/6/01*

November 27, 2001

Department of Natural Resources
Division of Oil and Gas
550 West 7th Ave, Suite 800
Anchorage, Alaska
99501-3560

Attention: Kevin Banks
Petroleum Market Analyst

**Re: Preliminary Finding and Determination for a Competitive Sale of Alaskan North Slope
Royalty Gas**

This letter is in support of Anadarko Petroleum Corporation's comments for consideration in the preparation of the "Final Finding" and the related "Invitation to Bid", as stated in their letter dated November 25, 2001 addressed to Kevin Banks.

AEC strongly advocates the sale of royalty-in-kind gas and the timeline and process set forth within the Preliminary Finding. We believe initiating the royalty-in-kind process and finalizing the awarded gas sales contracts as soon as possible is critical for current and future gas exploration within Alaska.

AEC and Anadarko are prepared to be active explorers for natural gas on the North Slope, provided we have access to the gas pipeline. Our efforts and activities will create competition and attract other gas players, which in turn will increase the State's revenue (e.g., royalties, land sales). We believe this is something unique to new explorers, which the Alaska Gas Producer Pipeline Team can not provide. An example supporting this view is BP's announcement on shutting down their frontier exploration in Alaska and switching to harvest mode.¹ AEC also believes Phillips' exploration will slow in Alaska due to their Conoco merger. We want to emphasize that when you consider the Royalty in Kind bids, there is significant upside benefit to the State that that will come from not only price premiums, but from the exploration activities of new players.

We reiterate our support for this royalty in-kind sales process as set forth in our testimony to the Royalty Board on November 13, 2001. If you have any questions, please contact Alan Sharp at (403) 261-2560.

Yours truly,

Alan Sharp
Director, Northern Business Development

¹ Petroleum News Alaska. Vol.6, No.18. Page 1, "What will it take to get BP's focus back on Alaska?".

RECEIVED

DEC 11 2001

DIV. OF OIL & GAS
DIRECTOR'S OFFICE



December 6, 2001

Mr. Pat Pourchot
Commissioner
State of Alaska
Department of Natural Resources
Division of Oil and Gas
550 West 7th Avenue, Suite 800
Anchorage, AK 99501-3510

Reference: *Williams Comments Submitted to The State of Alaska regarding the Preliminary Finding and Determination for a Competitive Sale of Alaska North Slope Royalty Gas ("Preliminary Finding")*

Dear Mr. Pourchot:

It is with great pleasure that Williams Energy Marketing & Trading submits comments to the State of Alaska pursuant to its request regarding the Preliminary Finding. We have reviewed the Preliminary Finding and respectfully submit the following comments and recommendations, which will become a part of the Published Final Finding and Invitation, scheduled to be published December 12, 2001:

**1. Section I – Introduction and Background
D-Schedule**

A. Proposed Schedule for the 2002 ANS RIK Natural Gas Sale

Williams Comments and/or Recommendation:

In our review of the Proposed Schedule for the 2002 ANS RIK Natural Gas Sale, we feel it is extremely restrictive and may be very difficult to administer by the State of Alaska. Williams recognizes the time constraints due to legislative approvals.

2. Section II – Developing Bid Proposals for The RIK Sale

A. To be considered, proposals must meet the following Minimum Cash Bonus Bid and Base Price Conditions

Williams Comments and/or Recommendation:

The proposed requirement to provide a Cash Bonus Bid is not a normal industry standard. The standard to qualify bidders is typically handled through a type of "Pre-Qualified Bidders Process" to screen for RFP bidders, which meets the desired criteria. Due to the preliminary nature of the pipeline project, a Cash Bonus is premature. However, as the pipeline develops as a viable project, Williams would entertain providing a Cash Advance with certain provisions for recovery.

3. Section II – Developing Bid Proposals for The RIK Sale

C. The following terms should be included in all proposals - Quantity and Transport Risk

Williams Comments and/or Recommendation:

Quantity and Transport should mirror each other in marketing your State Royalty Gas.

4. Section II – Developing Bid Proposals for The RIK Sale

C. The following terms should be included in all proposals - Term

Williams Comments and/or Recommendation

Term and Transport should mirror each other in marketing your State Royalty Gas. The industry standard transportation contract on a new proposed pipeline usually has a minimum term of ten (10) years. Williams' recommends that the State would need to evaluate longer-term structures for their sale of RIK.

Due to our recommendations related to the Cash Bonus Bid our comments are being submitted without a cash advance. I have attached a Williams Overview, which is the information we provide to our customers to Qualify Williams for Bidding. Williams Corporate Credit Rating is BBB+ rated by Standard and Poors Corporation. I have also included for your review Williams' Bank and Trade References.

We are extremely interested in marketing the State of Alaska's Royalty Gas. In addition, Williams is also interested in working with the State of Alaska and the Producer Consortium in a unified effort toward Commercializing the Alaska North Slope Gas. As you know, Williams has a full-time team dedicated to the Alaska North Slope Project.

Williams is extremely cognizant to the State's requirements for bringing In-State Value through this project. In addition, we feel we can provide some creative ideas to market the States Royalty Gas by providing increased value over RIV.

If you have any questions or need additional information, please feel free to call me at 918.573.3603 (office) or 918.645.7409 (cellular).

Sincerely,



Tamara J. Walden
Strategic Business Development
Vice President

TJW/tw

Attachments

Cc: Mark Myers, Director
Bonnie Robson, Deputy Director
Kevin Bank, Petroleum Market Analyst

Appendix B: Summary and Response to Comments

Ken Thompson

Ken Thompson, President of Pacific Rim Leadership Development, LLC and past-president of ARCO Alaska, Inc., responded to the Preliminary Finding in an e-mail dated November 19, 2001 and offered several suggestions as the State moves ahead through the sale process. The following is a summary of his comments and the department's response:

1) Mr. Thompson noted that the State has scheduled the sale process assuming that an "open season" will occur early in 2002. He recommended that State contact the three major North Slope producers to determine whether or not they were indeed planning an "open season" for the first quarter, 2002.

The producer project team has indicated to the department that no decision to hold an open season has been made as of yet. The team also said that an open season would not occur in the first quarter, 2002. The department is also aware that the Foothills Pipeline consortium has made progress to advance a pipeline project of its own and to develop a proposal for the North Slope producers. It is unlikely that an open season for a Foothills Pipeline project will occur in the first quarter, 2002.

The Royalty Board and Legislature must approve any contract(s) that the commissioner negotiates. If there is chance that a pipeline open season will occur anytime during 2002, the State still must proceed with the sale now so that the Legislature may review the contract in its upcoming 2002 session.

2) Mr. Thompson expressed his concern that RIK gas be available to supply in-state needs and advised the department to review its own study of in-state demand completed by Econ One. He recommended that there should be sufficient volumes of RIK gas to replace any potential shortfall of gas supplies in the Cook Inlet region. In a second comment on potential sale volume, he recommended that no more than 100,000 – 250,000 Mcf per day be sold in this sale (assuming total royalty gas production at 500,000 Mcf per day).

Seventy percent of the combined total royalty gas production from the Prudhoe Bay and Pt. Thomson units will be offered in this sale. The remaining 30 percent (possibly 150,000 Mcf per day) will be reserved for possible future competitive sales. In our review of proposals received as a result of the RIK sale offer, future in-state gas demand will be considered.

3) In a similar vein as number 2 above, Mr. Thompson recommends that the State limit the term of the RIK gas sale contract(s) that result from this sale to not more than 5 years.

Given the uncertainty surrounding the gas pipeline project at this stage, the State should preserve as much flexibility in a future RIK program as it can. Some potential buyers will require a RIK gas sale contract term equivalent to the term of

the firm transportation commitment they will have to make in the open season. The State's evaluation of proposals will have to balance the advantages of shorter term contracts to the State against the commercial requirements of the buyers to meet pipeline commitments.

- 4) If the notice of RIK sale yields more than one acceptable proposal, Mr. Thompson recommends that the State consider awarding more than one RIK gas sale contract and thereby create incentives among the buyers to pursue marketing opportunities for the State's RIK gas.

Together with his comments on volumes and contract term above, Mr. Thompson is recommending that the State cultivate customers who will be invited to bid in subsequent RIK sales as part of an ongoing RIK program. Such a program could very well evolve over time, in which the State sells much royalty gas in regular sales to a variety of in-state users and Lower 48 marketers. The department will continually evaluate the merits of such a program.

- 5) Mr. Thompson suggests that the sale price offered by the winning proposal could serve as an indicator of value under the lease terms. This price information could give the State some leverage as the producers make advance the pipeline projects.

It will depend on how the RIK price is ultimately calculated. The State may choose to use the RIK price in its determination of market value under the lease. Insofar as the Base Price is based on the volume-weighted average of the RIV value paid by the lessees, using the Base Price to measure RIV value would be circular.

- 6) Mr. Thompson proposes that the State offer and sell NGLs separately based on liquids prices versus a Btu-adjusted price.

The department is aware that the NGLs in the gas stream could add value to the State's royalty gas, both in terms of energy content per Mcf and also in the value per unit of energy. The requirement that the proposals provide a price that is at least equivalent to the RIV value should protect the State. The lease provisions provide that the State be fully compensated for the value of the liquids.

Anadarko Petroleum Corporation

Anadarko wrote in support of an RIK gas sale to the Royalty Board on November 12, 2001 and commented on the Preliminary Finding in a letter to the department dated November 27, 2001.

In its comments to the Royalty Board, Anadarko stressed its interest to purchase RIK gas "in conjunction with bidding for firm transportation" on the ANS gas pipeline. If Anadarko cannot participate in an open season and secure capacity on the pipeline now, its prospective gas discoveries on the North Slope may be stranded. Without RIK gas to fill a firm transportation commitment, Anadarko predicted it could face ship-or-pay demand charges on the pipeline of \$180 million per year.

Anadarko also predicted that the State could capitalize on the current interest in the State's royalty gas from a number of industry players. The requirement of a minimum cash bonus, potential option payments, and possible in-state investment commitments means that the State may realize some form of compensation for its royalty gas several years in advance of royalty production. The requirement that the price of RIK gas not be less than the value of RIV protects the State from potential downside impacts.

In its comments on the Preliminary Finding, Anadarko reiterated its desire to use RIK gas to cover its firm transportation commitments in the ANS gas pipeline. Anadarko also raised several questions about the contract terms described in the Preliminary Finding.

- 1) Anadarko encouraged the State not to limit the quantity of royalty gas offered in the sale.

The State will offer up to 70 percent of the combined total volume of royalty gas produced in the Prudhoe Bay and Pt. Thomson units.

- 2) Anadarko asked that the State not specify a contract term and instead allow potential buyers to include the length of the contract term commensurate with the term of the firm transportation commitment on the pipeline in their proposals.

The RIK offer will ask potential buyers to describe the contract term that they will require. The State recognizes that some potential buyers will require that the term of the RIK gas sale contract be equivalent to the term of their firm transportation commitments.

- 3) Anadarko asked that the State not define a Point of Delivery until the RIK gas sale contract is finally negotiated. Anadarko anticipates that the royalty gas that will be offered in this sale will require conditioning to extract CO₂ and other diluents. The State should secure these conditioning services for royalty gas prior to delivery to the RIK purchaser.

The contract defines the Point of Delivery as the location or locations where the State receives its royalty gas from the lessees. As for securing conditioning services before tendering its RIK to the buyer, the State may wish to preserve this option but will not take on the obligation to do so now.

- 4) Anadarko asked that the Final Finding include an RIK gas sale contract that will serve as the basis for contract negotiations. Anadarko also wanted the State to provide this contract to potential buyers to solicit comments.

Attached to this Finding is a copy of the *Sample Contract*.

- 5) Anadarko indicated that it would require a substantial volume of RIK to backstop the development of minimum economic gas discovery on the North Slope. For this reason it recommended that the State not award contracts to multiple bidders. The RIK sale offer should

include a provision that will allow a successful proposal to be withdrawn if it is awarded volumes that are less than the quantity proposed.

The State will make the determination to award one or more contracts on the merit of the proposals. If the award is for volumes insufficient to the winning proposal's requirements, the buyer may withdraw its proposal.

6) Anadarko is concerned that bidders not be allowed to initiate contact with the Division of Oil and Gas or the Royalty Board after proposals are revealed at the Opening.

A limitation on buyer-initiated contacts with the division must be specific to the RIK sale. The division will need to deal with some of the same buyers on many other issues. Contact with Royalty Board members by prospective RIK buyers is prohibited by 11 AAC 26.110.

7) According to Anadarko the Preliminary Finding left unclear whether the minimum cash bonus was only assessed against the winning proposal or a non-refundable payment due from all proposals.

Only the winning proposal(s) will be required to pay the minimum cash bonus. The minimum cash bonus will be refunded to buyers whose proposals are rejected. The State will also refund the minimum cash bonus if any of the conditions in Article VIII occur.

8) Anadarko suggested that the RIK gas price not be used in the determination of the RIV price because the RIK price will include a premium price added to the RIV base price.

It will depend on how the RIK price is ultimately calculated. The State may choose to use the RIK price in its determination of market value under the lease. Insofar as the Base Price is based on the volume-weighted average of the RIV value paid by the lessees, using the Base Price to measure RIV value would be circular.

9) Anadarko wants further explanation of the RIV value that appears in the discussion of the Base Price in order to reduce some of the uncertainty in its determination.

The Preliminary Finding included this discussion to provide potential buyers with an appreciation of the potential uncertainty related to the calculation of the Base Price.

10) Anadarko requested that the department consider adopting a reasonable statute of limitations for adjustment of RIV price to be used as the Base Price for RIK.

The department does not accept this recommendation.

11) Anadarko favored the requirement in the Preliminary Finding to impose some punitive recourse should the buyer fail to carry out the proposed in-state investments that appear in its proposal. This provision takes away the incentive for bidders to embellish and/or renege on the in-state investment commitments contained in their proposals.

The department has included those provisions.

12) Anadarko expressed the concern that the volume of gas sold under the contract must not exceed the buyer's firm transportation capacity.

The *Sample Contract* includes a provision that will allow the buyer to reduce its Maximum Quantities up to 50 percent upon two years advance notice. If the buyer wishes to reduce the Maximum Quantities by more than 50 percent, the buyer must pay a fee. The buyer may also adjust its monthly nomination.

13) Anadarko suggested that the State's discretion to nominate RIK gas from the Prudhoe Bay and Pt. Thomson units to supply the contract could disadvantage the buyer because of the way field costs are determined in each unit. Anadarko would prefer to take RIK gas from royalty gas sourced from leases other than the DL-1 leases within the Point Thompson Unit. If state RIK volumes sold to all buyers requires taking RIK from the Pt. Thomson Unit DL-1 leases, then the RIK from the Pt. Thomson DL-1 leases should be prorated to all buyers.

Article 3.1.5. in the *Sample Contract* addresses this issue.

14) Anadarko wants a condition precedent that will allow the buyer or seller to terminate the RIK gas sale contract if no open season has occurred prior to April 30, 2005. Anadarko also provided contract language that would allow the State or the buyer to terminate the RIK gas sale contract if the pipeline is not in-service by December 31, 2011. The State should defer its right to terminate the RIK until December 31, 2013 if the buyer is unable to terminate its firm transportation obligations.

According to Article VII of the *Sample Contract*, either party may terminate the RIK gas sale contract, if the open season for the gas pipeline is not completed by December 31, 2004. The agreement terminates if the pipeline is not in service by July 31, 2012 or no royalty gas has been delivered by that date. The State will refund the minimum cash bonus, without interest, if these conditions precedent occur. The State selected these dates to balance the requirements of potential purchasers with the State's requirements to take advantage of alternative opportunities as soon as possible should the pipeline project be delayed.

15) Anadarko raised several issues with respect to field costs and conditioning costs that may be allowed as royalty deductions in the calculation of value for RIV and RIK. It should be clear that any RIK gas that bears the field cost that the State would not have otherwise incurred must be borne by the buyer. What remains unclear to Anadarko is whether or not the State will bear a proportionate share of the gas conditioning costs. Anadarko would like to see in the RIK sale offer and the RIK gas sale contract how the Base Price based as it is on the RIV value would

include all deductions for transportation, treating and conditioning costs, field costs that might apply to RIK but not RIV.

The principle that governs the calculation of the Base Price is that the State will not be worse off for selling its royalty gas. The department cannot predict how the conditioning costs will be accounted for in the calculation of RIV value. The RIK gas sale contract will require that the purchaser pay any and all field and conditioning costs chargeable against the State's royalty share of gas subject to the contract.

16) Anadarko objected to the timing for the State to suspend performance or terminate the contract if the buyer fails to make full payment within one day's notice that payment is past due.

Article 9.1.1(i) allows two business days.

17) Anadarko recommended that the text in Section III.G. in the Preliminary Finding be redrafted in the Final Finding, RIK sale offer, and RIK gas sale contract to clarify that the Commissioner's finding under the procedures of Article XII "Interpretation of Terms and Conditions" may be appealed in court.

The buyer may appeal the commissioner's decisions. The State is unwilling to add any provision that limits its discretion and deference to its decisions.

18) Anadarko supports the inclusion of a contract provision that will facilitate changes to the RIK gas sale contract in order to preserve the intent of the parties should changes in the market occur during the course of the contract.

The department will consider a Reopener provision in Article XXVI in the *Sample Contract*.

19) Anadarko asked that the Final Finding clarify that an RIK sale that results in incremental in-State benefits is not contrary to state regulations as long as the RIK sale terms do not create a situation where the State is subsidizing the buyer.

The State has an interest in facilitating in-state investments and the State may use its RIK to achieve this goal.

AEC Marketing (USA) Inc.

AEC Marketing (USA) Inc. ("Alberta Energy") supports the RIK gas sale. In a letter dated November 9, 2001 to the Royalty Board, Alberta Energy provided a transcript of its testimony for the Royalty Board hearing. This testimony provides detailed discussion of the situation faced by new explorers in the Brook Range foothills. Alberta Energy fears that the lack of pipeline capacity could postpone production of gas from its prospective exploration targets for more than 20 years. Explorers like Alberta Energy will have to obtain firm transportation capacity in the first open season or face the possibility that an expansion of the pipeline sometime in the future

will not occur when Alberta Energy's will want to develop its prospects. The substantial risk of assuming a firm transportation commitment is a burden on Alberta Energy's exploration program. Alberta Energy is interested in RIK gas as a backstop to its own supply to fill the firm transportation commitment.

In its testimony and referenced in its comments on the Preliminary Finding dated November 27, 2001, Alberta Energy requested that the State leave as many terms and conditions open as possible for the proposals. Given the uncertainty in the details of an RIK gas sale contract, Alberta Energy feels that bidders can bring creativity and innovation to maximize value for the State.

The issue of future access to the pipeline by currently non-producers on the North Slope and potential in-state users of ANS gas prompted the State to conduct the RIK sale. While many terms in the RIK gas sale contract will be open for proposals, other terms dealing with the department's rights in normally found in recent RIK gas sale contracts are not subject to negotiation.

Williams Energy Marketing & Trading

Williams' comment letter arrived on December 6, 2001 after the November 30, 2001 deadline. Williams indicated an interest in marketing the State's ANS royalty gas and provided four comments on the sale:

1) Williams felt that the schedule for the sale was extremely restrictive and may be difficult to administer by the State.

Our schedule is driven by the need to provide RIK gas supply to potential buyers so that the buyers can participate in an open season. Although the open season, if it will occur, will not be scheduled in the first quarter, 2002. The timing of the Legislative session compels the State to hold the RIK gas sale now. Some of the milestones in the schedule published in the Preliminary Finding have been postponed to prepare the Final Finding and other sale documents and to give the State more time to negotiate with the winning proposals.

2) Williams argued that a minimum cash bonus is not a normal industry standard and rather felt that the State should pre-qualify bidders.

The minimum cash bonus is intended to cover the cost of the sale. Only the winning proposal(s) will pay the minimum cash bonus and the cash bonus will be refunded should the any of the conditions precedent in Article VIII occurs.

3) Williams recommended that the volume sold in the RIK gas sale contract equal the transportation capacity.

The buyers of the State's RIK gas will have to arrange their own transportation capacity. Buyers must indicate the volume each will require. The *Sample*

Contract included in the RIK sale offer has quantity provisions that allow for some flexibility to adjust the volume taken by the buyer to match the buyer's firm transportation commitments.

- 4) Williams also recommended that the term of the contract mirror the term usually found in industry-standard transportation contracts.

The State will consider proposals that include a provision to match the length of the contract term with the firm transportation commitment.

Phillips Alaska, Inc.

In a letter dated November 30, 2001, Phillips recommended that the RIK sale does not need to be so quickly paced. Phillips does not foresee holding an open season during the first quarter 2002. Phillips also said the stated reasons to hold the RIK sale to backstop future gas production from unexplored leases will burden the economics of the pipeline project. Phillips argues that the RIK sale creates a situation that the owners of the proven reserves may be reduced to make room for the new production from the unexplored leases. This reduction may lead to under-utilization of the gas treatment plant and other on-lease investments made for gas sales. This reduction will mean that the known resource owners who bear the risk of building the pipeline will be insufficiently rewarded. The RIK sale will transfer the benefits of the long-term commitments to new participants without transferring the associated risk.

Phillips recommends that fair and unbiased capacity allocation and expansion procedures can be achieved through the FERC regulatory process. Future North Slope gas producers will have access to the pipeline.

The RIK sale is scheduled to allow the Legislature in its next session to vote on the sale. If an open season is scheduled any time during 2002, the RIK gas sale contract(s) must be brought to the 2002 legislative session so that the buyers have gas supplies to fill their transportation commitments.

While an RIK sale may complicate the evaluation of a pipeline project, the ability to shift from RIK to RIV is a lease right of the State that may prove to be very important to the State. Access for explorers is one of the reasons for selling RIK gas now; in-state users may also participate in the sale. The producers acknowledge that the FERC cannot compel a pipeline owner to expand capacity. It is presumed that competitive market forces will provide the necessary incentives.

As to the impact of the RIK sale on the economics of the pipeline project, Phillips has not provided to the State a quantitative analysis. Our qualitative evaluation of the explorer backstop scenario suggest that should the explorers back out RIK gas in place of gas production from their unexplored leases, the producers are provided with the benefits of producing greater equity volumes in the first few years of pipeline operation than they would produce without the sale. After the

switch from RIK to RIV the producers will have the incentive to expand the pipeline to maintain equity volumes. An open season after initial construction could also attract new entrants including in-state users of gas. Phillips may be among those looking for space in the new expansion as its own unexplored leases begin producing.

BP Exploration (Alaska), Inc.

The language of BP's letter, dated November 30, 2001, mirrored that which appeared in the Phillips letter. BP asked that the State refrain from taking steps that would jeopardize the commercial viability of the pipeline project.

BP added that it is not opposed to the State marketing its royalty gas and suggested that it may bid in the RIK sale. BP also suggested that the RIK sale might address some of the industry's concerns about fiscal certainty for the project by providing clear and transparent pricing for royalty gas.

The State's responses to BP's critiques are the same as those listed above for Phillips. Depending on the price structure adopted for the RIK gas sale, the State may choose to refer to the RIK gas price in its evaluation of the value of RIV gas.

Appendix C: In-State Natural Gas Demand and Supply Issues

The Division of Oil and Gas has reviewed the final draft of the "Alaska Natural Gas In-State Demand Study" completed under contract for the Department of Natural Resources by Econ One Research. This report will be available by December 28, 2001. This Appendix is a summary of the study.

Baseline Conditions. The total in-state demand for natural gas was approximately 227 Bcf per year in 2000. This estimate is based on annual usage averaged over the period 1996-2000. It includes LNG exports (78 Bcf per year) and other industrial uses in Southcentral Alaska, as well as approximately 10 Bcf per year of industrial gas usage for TAPS pump station and other North Slope oil field operations (but excludes gas re-injection for enhance oil recovery). Industrial gas usage accounts for about 71 percent of the statewide total. The remainder is somewhat evenly divided between residential/commercial gas usage and gas for electric power generation in Southcentral Alaska. A modest quantity of natural gas (less than 2 Bcf per year) is consumed space heating and power in Barrow and for space heating in Fairbanks.¹

Potential for Growth in Gas Usage. In-state gas usage over the next two decades has the potential to increase by approximately 140 Bcf per year. The potential for growth in gas usage is may arise from several sources. The sources of growth and their estimated additional gas usage in 2020 are:

- Baseline economic growth (27 Bcf per year)
- Expanded residential/commercial gas service in Southcentral and Interior (7 Bcf per year)
- Expanded existing industrial usage at the Kenai Ammonia-Urea plant (4 Bcf per year)
- New plant expansion at the Kenai Ammonia-Urea plant (30 Bcf)
- New petrochemical plant (28 Bcf per year)
- Fuel switching for power generation in Interior communities (30 Bcf per year)
- Gas-by-Wire; central station power generation near Fairbanks (13 Bcf per year)

Three key assumptions underpin the preceding estimates for potential growth in gas usage: (1) relative energy prices in the future are consistent with levels observed today; (2) the state's regional economy exhibits continued gradual economic expansion at rates comparable with the past five years (about a half percent per year in real dollars); and (3) in-state access to ANS gas from a high-pressure, dense-phase gas pipeline from the North Slope to Canadian and Lower-48 destinations is not cost prohibitive.

This latter assumption merits further consideration. The results in the division's study of in-state natural gas demand and supply suggest that several factors may challenge the economics of in-state access to ANS gas. For example, under the assumptions: (1) 100 percent penetration for 11,000 residential customers, (2) a gas commodity price comparable to what ENSTAR currently pays for gas in Southcentral, and (3) a 12-year payback for the \$1,000 cost of home furnace and water heater conversion, expanded residential gas usage in the Interior region is approximately

¹ Barrow residents consume gas from local gas fields. Northern Eclipse, LLC ships daily truckloads of LNG from Southcentral Alaska to Fairbanks Natural Gas LLC, the local distribution company in Fairbanks.

competitive with electricity, the next least-cost alternative. But 100 percent penetration is not likely and a 12-year payback is not attractive.²

In effect, economies of scale for expansion of residential service to the Interior region do not appear to be sufficient to offset the levelized capital costs for gas transmission from the North Slope to Fairbanks (\$1.00 per Mcf), gasoline tap and meter/stepdown (\$0.05 per Mcf) and the corresponding distribution system (\$2.29 per Mcf).

Industrial operations in Southcentral and the North Slope account for the bulk of current gas usage. The potential for increased gas usage by greater utilization of existing industrial capacity is limited to perhaps 3-to-4 Bcf per year at the Ammonia-Urea plant in Kenai, based on historic gas consumption rates. A moderately-sized Internet data center would consume modest quantities of gas (less than 1 Bcf per year). However, a relatively large Internet data center (one-million square feet) could consume as much as 4.3 Bcf per year. A polyethylene petrochemical plant similar to the facility under study by Williams could draw 300-400 Bcf per year for ethane extraction and possibly other natural gas liquid components. But most of this gas would be re-injected back into the gas pipeline in the form of methane, destined for other downstream markets. Net gas usage at the petrochemical probably would be less than 30 Bcf per year.

The in-state gas demand and supply study identified community power-generating facilities in the Interior region that could potentially switch their primary fuel to natural gas. Fuel oil and diesel facilities in the Interior region of the state were the most attractive candidates. There are approximately 200 MWs of capacity in this region that could shift from fuel oil to natural gas. This alternative appears to meet first-order economic criteria but at a very small scale (30 Bcf per year).

The study also considered using ANS gas for central-station electric power generation and transmission in the Interior region (gas-by-wire). The economics of a 250 MW combined cycle facility stack up favorably with the costs of existing generating units. However, the state does not have a potential capacity need until the year 2014.

In sum, the economics of supplying ANS gas for the applications outlined above as a whole do not appear to be favorable. Where the economics are close (fuel switching and gas-by-wire) additional, detailed engineering analysis of related transportation and distribution alternatives is required before conclusions can be reached.

The Cook Inlet Gas Demand and Supply Balance. Setting aside the potential for future increases in gas usage, the evidence regarding existing gas supply and demand in Cook Inlet suggests that, without access to additional gas reserves, annual gas deliverability in the ENSTAR system may fall short of potential demand (at current, relative energy prices) before 2010. This imbalance stems in part from a long-standing availability of relatively inexpensive gas to Southcentral users in all customer classifications. To some extent, gas producers and consumers have responded to the potential for future supply shortages. For example, the Regulatory Commission of Alaska recently approved a gas purchase agreement between ENSTAR and Unocal that ties gas price to a three-year moving average of the Henry Hub spot market price

² Penetration in areas currently served by ENSTAR in Southcentral Alaska is approximately 80 percent.

with a floor of \$2.75 per Mcf. The agreement also commits Unocal to an aggressive program of gas exploration in the Cook Inlet.³ The impact of rising gas prices is likely to result in curtailment of industrial gas usage. Also, a situation of acute supply shortage is likely to reduce the U.S. Department of Energy's willingness to renew an application to extend the license to export LNG to Japanese Utilities beyond the current expiration date of April 2009.

The division's investigation of in-state gas demand and supply evaluated the potential for ANS gas to serve the demand-supply imbalance in the Southcentral region. Preliminary findings indicate that a the levelized cost of a 16-to-20 inch spur pipeline linking Southcentral with the ANS gas pipeline at Fairbanks could be competitive with energy alternatives (such as fuel oil or LNG imports into Cook Inlet) if annual throughput exceeds 30-to-40 Bcf per year. For example, a 20-inch spur pipeline operating at an average of 40 Bcf per year for 30 years would imply meter-station step-down charges and levelized transmission charges of approximately \$1.00 per Mcf (excluding the toll to Fairbanks, as well as local distribution and gas commodity charges). In order to be competitive, the spur pipeline would be required to serve a segment of the existing Southcentral customer base now served by local gas reserves in the Cook Inlet Basin. This result could be favorably influence by scale economies from:

- Sharing spur pipeline transmission charges over a wider customer base along the energy belt;
- Higher rates of penetration than those observed among Southcentral users within the existing ENSTAR system;
- System-wide averaging of distribution charges; and
- Baseline growth in all customer classes including industrial users and expanded gas service.

³ Regulatory Commission of Alaska. Docket Number U-01-7, Order 8. *Order Conditionally Approving TA 117-4 (Gas Sales Agreement) and Requiring Filing*. October 25, 2001.

Appendix D: *Sample Contract* for the Sale of ANS Royalty Gas

**SAMPLE CONTRACT
FOR THE SALE OF
ANS ROYALTY GAS**

This Sample Contract shows the type of contract the State expects to negotiate for the sale of ANS Royalty Gas. It is illustrative only. It is not an offer to sell ANS Royalty Gas. Volumes are expressed in MMcf and prices are expressed as dollars per MMcf. It may be appropriate to use MMBtus instead of MMcfs. Negotiations with purchasers will set the actual terms and conditions of contracts for the sale of ANS Royalty Gas.

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SAMPLE CONTRACT

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**AGREEMENT FOR THE SALE AND
PURCHASE OF ROYALTY GAS**

This Agreement is between the State of Alaska ("State") and _____
("Buyer"). The effective date of this Agreement is _____, 2002.

**ARTICLE I
DEFINITIONS**

As used in this Agreement, the terms listed below shall have the following meanings:

1.1 "Commissioner" means the Commissioner of the Alaska Department of Natural Resources or the Commissioner's designee.

1.2 "Day" means a period of twenty-four (24) consecutive hours, beginning at 12:00:01 a.m., Alaska Standard Time.

1.3 "Gas" means natural gas tendered in gaseous phase by the Lessees to the State as royalty. Gas [includes] [excludes] natural gas liquids ("NGLs") tendered by the Lessees as Royalty Gas.

1.4 "Gas Pipeline" means the pipeline and related facilities to be constructed to deliver ANS gas from the North Slope to markets inside or outside the State of Alaska.

1.5 "Leases" means the oil and gas leases issued by the State and subject to the terms of either the Prudhoe Bay Unit Agreement or Point Thomson Unit Agreement.

1.6 "Lessee" means a person, as "person" is defined in Alaska Statutes 01.10.060, owning a working interest in any of the Leases.

1.7 "Mcf"; "MMcf"; "Bcf" – "Mcf" means one thousand (1,000) Standard Cubic Feet; "MMcf" means one million (1,000,000) Standard Cubic Feet; and "Bcf" means one billion (1,000,000,000) Standard Cubic Feet.

1.8 "MMBtu" means one million (1,000,000) British Thermal Units.

1.9 "Month" means a period beginning at 12:00:01 a.m., Alaska Standard Time, on the first Day of the calendar Month and ending at 12:00:01 a.m., Alaska Standard Time, on the first Day of the following calendar Month.

1.10 "Nomination" is defined in Paragraph 3.1.4.

1.11 "Open Season" means the period during which shippers must contract for space on the Gas Pipeline.

1.12 "Parties" means, collectively, Buyer and State.

1.13 "Party" means Buyer or State, individually.

1.14 "Point of Delivery" means the location or locations where the State receives Royalty Gas in-kind from the Lessees.

1.15 "Reserved Gas" is defined in Paragraph 3.1.5(a).

1.16 "Royalty Gas" means that portion of Total Royalty Gas the State has agreed to sell to Buyer and Buyer has agreed to purchase under this Agreement.

1.17 "Royalty Value" is defined and calculated as shown in Paragraph 3.3.1 and Exhibit 1.

1.18 "Total Royalty Gas" means the total volume of Gas produced each Day from the Prudhoe Bay and Point Thomson units that the State takes as its royalty under the Leases, whether in-kind or in-value.

1.19 "Unit Agreement" means the Prudhoe Bay or Point Thomson unit agreement, as appropriate.

1.20 "Unit" means the Prudhoe Bay Unit or the Point Thomson Unit, as appropriate.

ARTICLE II

SPECIAL COMMITMENTS

[This Article is reserved for Special Commitments offered by Buyer. A Special Commitment could be a commitment to in-state processing, in-state use, in-state investment, in-state exploration, local hire, or anything else that Buyer offers to enhance its proposal. Performance of a Special Commitment must be measurable and enforceable. A Buyer is not required to propose a Special Commitment. Special Commitments may be given weight in the State's evaluation process.]

ARTICLE III

SALE AND PURCHASE OF GAS

3.1 Quantity.

3.1.1 **Maximum Quantities.** The State agrees to sell and the Buyer agrees to buy each day Royalty Gas in the quantities shown in the attached Schedule 1, "Royalty Gas Purchase Schedule." The quantities shown in Schedule 1 are the Maximum Quantities available to Buyer.

3.1.2 **Reduction in Maximum Quantities.** The Buyer may at any time reduce the Maximum Quantities by giving two years notice. No quantity shown in Schedule 1 may be reduced by more than fifty percent (50%).

3.1.3 **No Guarantee of Quantity.** The State can deliver Royalty Gas only to the extent it receives Royalty Gas from the Lessees. The quantity of Total Royalty Gas available to the State may vary and may be interrupted from time to time depending on a variety of factors, including the rate of production from the Leases and Units. Furthermore, the State is or may be required to nominate Royalty Gas as a percentage of Total Royalty Gas, and not by quantity. The State disclaims and Buyer waives any guarantee, representation, or warranty, either express or implied, that a specific quantity of the total, daily, monthly, average or aggregate Royalty Gas will be delivered to Buyer under this Agreement. Buyer disclaims any interest in or right to stored Royalty Gas to which the State is or may become entitled.

3.1.4 Monthly Nomination to Take Less Than the Maximum Quantities. Buyer may request an increase or decrease in the quantity of Royalty Gas it will take each Month (a "Nomination"). A Nomination must be in writing and shall be effective on the first Day of the seventh Month after the Nomination is received by the State. The Nomination for any Month:

- a. cannot exceed the Maximum Quantities for that Month; and
- b. cannot change the Nomination for the prior Month by more than the percent change allowed by the applicable Unit Agreement.

3.1.5 Source of Royalty Gas. The State will deliver the quantities nominated by Buyer first from the Prudhoe Bay Unit and, if adequate Royalty Gas is not available from the Prudhoe Bay Unit, then from the Point Thomson Unit, subject to the following rules and conditions:

- a. The State reserves for later sale or any other use thirty percent (30%) of the Total Royalty Gas produced each Month from each Unit ("Reserved Gas"). Reserved Gas shall not be available to supply quantities nominated by Buyer.
- b. If the quantity of Total Royalty Gas sold under this Agreement and any other agreements exceeds seventy percent (70%) of the Total Royalty Gas produced each Month from the Prudhoe Bay Unit, the quantities nominated by Buyer shall be taken pro rata from the Prudhoe Bay Unit based on the ratio of Buyer's nominated quantities for the Month to total quantities nominated by all buyers for the Month. For example, assume (1) that the Prudhoe Bay Unit produces 1,000 MMcf in a given Month, (2) that Buyer's Nomination for that Month is 500 MMcf, and (3) that all other buyers under other agreements have nominations which total 400 MMcf. After the State's reservation of 30 percent (which could be reduced by a later sale), 700 MMcf are available. Nominations total 900 MMcf. Buyer would therefore receive

from the Prudhoe Bay Unit $500/900 \times 700 = 388$ MMcf, and the balance (112 MMcf) from the Point Thomson Unit.

3.1.6 State's Warranty of Title. The State warrants that it has good and marketable title to the Royalty Gas delivered and sold under this Agreement.

3.2 Quality.

3.2.1 Quality of Royalty Gas. The Royalty Gas sold under this Agreement shall be of the same quality as the Royalty Gas produced from the Units and delivered by the Lessees to the State at the Point of Delivery. The quality of the Royalty Gas may vary from time to time. The State disclaims, and Buyer waives, any guarantee, representation, or warranty, either expressed or implied, of merchantability, fitness for use, or suitability for any particular use or purpose, or otherwise, and of any specific, average, or overall quality or characteristic of Royalty Gas delivered under this Agreement. Buyer specifically waives any claim that any liquid or other hydrocarbons delivered with the Royalty Gas are not Royalty Gas for purposes of this Agreement.

3.3 Price of Royalty Gas. The Buyer shall pay the State a Royalty Gas price ("Price") for each Mcf of Royalty Gas purchased from the State. The Price shall equal the Base Price plus the Price Premium.

3.3.1 Base Price. The Base Price shall be the greater of \$___ per Mcf or the Royalty Value per Mcf for Gas taken from each Unit. The Royalty Value shall be the volume-weighted average of the amounts per Mcf paid in royalty by all Lessees each Month on Total Royalty Gas not taken in-kind, plus any processing and field costs incurred by the State on the Royalty Gas which would not have been incurred if the Royalty Gas had been taken in value. An example of the calculation of the Base Price is shown in Exhibit 1.

3.3.2 Price Premium. [This paragraph is reserved for any price premium a Buyer wishes to offer.]

3.4 Reservation Fee. If, in any Month, Buyer does not nominate the Maximum Quantities in effect for that Month, Buyer shall pay, in addition to the Price, a reservation fee equal to _____ percent of the Price on the difference in quantity between the Maximum Quantities and the quantity of Royalty Gas actually purchased as a result of Buyer's Nomination for the Month.

3.5 Current and Future Agreements, and Arbitration and Litigation Results Between the State and the Lessees.

3.5.1 Non-Intervention. The Buyer shall not intervene or otherwise participate in any way in any discussions, negotiations, agreements, settlements, reopeners, audits, arbitration, or litigation between the State and Lessees pertaining to royalty, nor shall the Buyer have any independent right to invoke any provision of any agreement between the State and Lessees.

3.5.2 Binding Effect. The Buyer agrees to be conclusively bound by the terms of any agreements, settlements, reopeners, audits, arbitration, or litigation between the State and Lessees pertaining to royalty, regardless of whether the Buyer agrees with or consents to the agreements, settlements, reopeners, audits, arbitration, or litigation.

3.6 Delivery of Royalty Gas.

3.6.1 Day of First Delivery. The State will make its first delivery of Royalty Gas to Buyer at the Point of Delivery immediately upon the State's first receipt of Royalty Gas from the Lessees.

3.6.2 Later Deliveries. After the first delivery, the State shall tender Royalty Gas to Buyer at the Point of Delivery immediately upon receipt of the Royalty Gas from the Lessees.

3.7 Passage of Title and Risk of Loss. Title to, and risk of loss of, the Royalty Gas shall pass from the State to Buyer for all purposes when the State tenders the Royalty Gas to Buyer at the Point of Delivery. Buyer shall bear all risk and responsibility for the Royalty Gas after passage of title.

3.8 Indemnification After Passage of Title. Buyer shall indemnify and hold the State harmless from and against any and all claims, costs, damages (including reasonably foreseeable consequential damages), expenses, or causes of action arising from or related to any transaction or event in any way related to the Royalty Gas after title has passed to Buyer.

3.9 Transportation Arrangements. Buyer shall make all arrangements for, and bear all costs of, transportation of the Royalty Gas from the Point of Delivery to, through, and away from the Gas Pipeline, and shall be responsible for meeting any requirements imposed by the Gas Pipeline or any other pipeline used to transport the Royalty Gas purchased under this Agreement. On the State's request, Buyer shall provide the State with evidence of (1) the arrangements for transportation of the Royalty Gas from the Point of Delivery, to, through, and away from the Gas Pipeline; (2) arrangements for resale, exchange, or other disposal of the Royalty Gas; (3) arrangements for the treating, conditioning, or processing of the Royalty Gas; (4) information on specific deliveries of Royalty Gas by Buyer to the Gas Pipeline. Buyer's failure to provide information, evidence, or assurances requested by the State shall, at the State's election and after notice to Buyer, constitute a material default under this Agreement.

3.10 Absolute Obligations. Buyer's obligations to pay for the Royalty Gas, provide security as required by Article 6 and 10.3, pay reservation fees, and purchase, transport, and dispose of Royalty Gas are absolute. These obligations shall not be excused or discharged by the operation of any disability of Buyer, event of force majeure, impracticability of performance, change in conditions, or other reason or cause.

ARTICLE IV **INVOICING AND PAYMENT**

4.1 Production Month Invoices. On or before the tenth business Day of each Month after the first Month of delivery of Royalty Gas, the State shall send to Buyer a statement of account with

an invoice for the total amount due for the estimated quantity of Royalty Gas delivered to Buyer during the immediately preceding Month and the estimated Price applicable to those deliveries. The State will base its estimates on the best information reasonably available to the State. The State shall adjust production month invoices as provided in Article 4.4 and Article 4.6.

4.2 Payment of Production Month Invoices. Buyer shall pay the total amount of each production month invoice, in full, on or before the third business Day after the date of the statement of account that includes the invoice. Any amount not paid in full on or before the third business Day after the date of the statement of account shall accrue interest as provided in Article 4.8, and become subject to the late payment provisions of Article 4.10, and any other remedies available to the State under this Agreement or at law.

4.3 Adjustments. Buyer acknowledges that any time after a production month invoice is sent, the State may receive more accurate information concerning the actual quantity, quality, and Price for Royalty Gas delivered to Buyer. Buyer agrees that any time such information becomes available to the State, the State may make adjustments to the preceding invoice(s), and invoice Buyer for the adjustments, plus interest as provided in Article 4.8 on the amount of any adjustment.

Buyer should expect adjustments to be made over a period of years and to increase the Price for Royalty Gas.

4.4 Initial Adjustments. Any adjustment made to an invoice issued during the immediately preceding month is an initial adjustment.

4.5 Payment of Initial Adjustments. Buyer shall pay the total amount of each initial adjustment invoice, plus interest as provided in Article 4.8, in full, on or before the third business Day after the date of the statement of account that includes the initial adjustment invoice. If an adjustment is due to Buyer for an overpayment, the State shall credit or refund to Buyer the amount of the overpayment, plus interest as provided in Article 4.8, on or before the third business Day after

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the date of the statement of account that includes the initial adjustment invoice. Any amount Buyer does not pay in full when due shall become subject to the late payment provisions of Article 4.10, and any other remedies available to the State under this Agreement or at law.

4.6 Subsequent Adjustments. Any adjustment made to an invoice issued prior to the immediately preceding month is a subsequent adjustment.

4.7 Payment of Subsequent Adjustments. Buyer shall pay in full the total amount of each subsequent adjustment invoice, plus interest as provided in Article 4.8, on or before the thirtieth Day after the date of the statement of account that includes the subsequent adjustment invoice. If an adjustment is due to Buyer for an overpayment, the State shall credit or refund to Buyer the amount of the overpayment, plus interest as provided in Article 4.8, on or before the thirtieth Day after the date of the statement of account that includes the adjustment invoice. Any amount Buyer does not pay in full when due shall become subject to the late payment provisions of Article 4.9, and any other remedies available to the State under this Agreement or at law.

4.8 Interest. All amounts Buyer does not pay in full when due under this Agreement, and all amounts invoiced as adjustments for underpayments and overpayments for Royalty Gas delivered to Buyer, shall bear interest from the date accrued until paid in full at the rate provided by Alaska Statute 38.05.135(d), or as that statutory provision may later be amended. In this Agreement, "date accrued" means the third business Day after the date of the first statement of account that contains the production month invoice to which the initial or subsequent adjustment applies. Exhibits 2 and 3 illustrate accrual of interest and other calculations under Article IV.

4.9 Non-Termination and Limitations. Buyer acknowledges that the State may continue to make adjustments after termination of this Agreement, and agrees that the provisions of Articles IV and IX shall survive termination of this Agreement for any reason.

4.10 Late Payment Penalty. In addition to all other remedies available to the State, if Buyer fails to make timely payment in full of any amount due, Buyer shall pay the State an amount equal to five percent of the amount not timely paid as a late payment penalty, in addition to the amount not paid when due, plus interest as provided in Article 4.8 from the date accrued until paid in full.

4.11 Disputed Payments. If a dispute arises concerning the amount of an invoice, Buyer agrees to pay the full amount of the invoice when due pending final resolution of the dispute.

4.12 Confidential Information. The State and Buyer agree that the State may invoice Buyer for, and Buyer agrees to pay, amounts that are based upon confidential information held or received by the State. If confidential information is used as the basis for an invoice, upon receipt of a written request from Buyer, the State shall furnish to Buyer a certified statement of the Commissioner to the effect that, based upon the best information available to the State, the invoiced amounts are correct.

4.13 Manner of Payment. Buyer shall pay all invoices in full within the times specified and without any deduction, set off, or withholding. Buyer shall pay all invoices by wire transfer of immediately available funds to the State's account at the following address:

State Street Bank & Trust Company
Boston, Massachusetts
ABA No. 011000028
For credit to the State of Alaska
General Investment Fund, AY01
Account No. 00657189
Attn: Kim Chan, Public Funds

Buyer shall pay an invoice in any other manner or to any other address the State has specified in an invoice or by other written notice. All other payments due shall be paid in the same manner and according to the same time schedule provided in this Article. If payment falls due on a Saturday, Sunday, or legal federal holiday, payment shall be made on the next business day.

4.13.1 Direct Payment to Lessees. If the State directs Buyer in an invoice or other writing to remit all or a portion of a payment required under this Agreement directly to one or more of the Lessees, Buyer shall remit the payment to the Lessee or Lessees in the manner designated by the State, and within the time limits specified in Article IV. The State may, in writing, authorize a Lessee to request direct remittance of all or a portion of a payment due under this Agreement, and to designate the manner for payment. Unless otherwise specified by the State in writing, the balance of a direct partial payment to a Lessee, and all subsequent payments, shall be made to the State in accordance with Article IV.

4.13.2 Direct Payment to Other Third Parties. Upon a determination by the State that remittance to a third party of an amount due under this Agreement will assist the State in monitoring or enforcing the Agreement, the State may direct Buyer in an invoice or other writing to remit all or a portion of a payment due under this Agreement directly to a designated third party other than a Lessee, and Buyer shall remit the payment to the designated third party in the manner designated by the State, and within the time limits specified in Article IV. Unless otherwise specified by the State in writing, the balance of a direct partial payment to a third party, and all subsequent payments, shall be made to the State in accordance with Article IV.

4.13.3 Direct Payment to State. In the event of any default by Buyer, including, without limitation, failure to make any payment when due, the State may demand payment directly from any person or entity which purchases Royalty Gas from Buyer.

ARTICLE V

BUYER'S REPRESENTATIONS AND OBLIGATIONS

5.1 Good Standing and Due Authorization. Buyer warrants that it is, and shall remain at all times during the term of this Agreement: (1) a corporation organized and existing under the laws of the United States or of a state, territory, or the District of Columbia; (2) qualified to do

business in Alaska; and (3) in good standing with the State. Buyer warrants that it has all corporate power and authority necessary, and has performed all corporate action required, to enter into and fulfill its obligations under this Agreement.

5.2 Financial Condition. Buyer warrants: (1) that all financial information submitted to the State is complete, accurate, and fairly represents Buyer's financial condition at the time of submission; and (2) that there has been no material change in Buyer's financial condition, business operations, or properties since it submitted the financial information to the State. Buyer warrants that the financial information was prepared in accordance with generally accepted accounting principles. Buyer shall immediately inform the State of any material change in its financial condition, business operations, agreements, or property that may affect its ability to perform its obligations under this Agreement. Buyer shall immediately inform the State of any significant change in ownership of Buyer or of Buyer's parent company or affiliates.

5.3 Financial Statements. Within one hundred and twenty Days after the end of its fiscal year, Buyer shall, at its own cost and expense, submit to the State a complete financial report. The report shall include Buyer's balance sheet as of the close of the fiscal year and the income statement for that year prepared in accordance with generally accepted accounting principles. The report shall include a copy of Buyer's annual report (if any) filed with the United States Securities and Exchange Commission pursuant to Section 13 or 15(d) of the Security Exchange Act of 1934. From time to time the State may require submission of additional financial information in such form or forms as the State may prescribe.

ARTICLE VI

SECURITY

6.1 Letter of Credit. Seven months before the Day of First Delivery, Buyer shall deliver to the State an irrevocable stand-by letter of credit (the "Letter"). The Letter shall be in a form

satisfactory to the Commissioner and shall be in effect by the Day of First Delivery. It shall be issued for the benefit of the State by a state or national banking institution of the United States that is insured by the Federal Deposit Insurance Corporation and has an aggregate capital and surplus amount of not less than One Hundred Million Dollars (\$100,000,000) ("Issuer"), or other banking institution acceptable to the Commissioner. The principal face amount of the Letter shall be an amount estimated by the Commissioner to be equal to the value of all Royalty Gas to be delivered by the State to Buyer during the 180 Days immediately following the Day of First Delivery. The Letter shall not require the State to submit any documentation in support of drafts drawn against it other than a certified statement by the Commissioner and the State's Attorney General that Buyer is liable to the State for an amount of money equal to the amount of the draft, that the amount of money is due and payable in full, and it has not been timely paid.

The Letter shall provide that the State has the right to draw and present drafts to the Issuer through _____ months after the State's last delivery of Royalty Gas to Buyer under this Agreement. The Letter shall be in effect continuously from the Day of First Delivery through _____ months after the date of the State's last delivery of Royalty Gas to Buyer. If the Letter is not in effect for any reason, (1) Buyer shall be deemed to have materially breached this Agreement; (2) a default under Article IX will have occurred; and (3) all Buyer's obligations, expenses, and liabilities accrued as of that date, whether yet due and payable, shall become immediately due and payable in full.

If the State asserts a claim or claims that equal a total amount of money greater than the principal face amount of the Letter in effect, Buyer shall, upon the State's request, cause the principal face amount of the Letter to be increased by an amount sufficient to secure the total amount of the State's claims. Buyer is subject to this obligation even if Buyer denies, rejects, or otherwise contests the State's claims.

If the principal face amount of the effective letter of credit is ever less than the estimated price of 180 Days of Royalty Gas deliveries, Buyer shall automatically and immediately cause the principal face amount of the effective Letter to be increased to an amount equal to the estimated price of 180 Days delivery of Royalty Gas. If the principal face amount of the effective Letter is greater than the estimated price of 180 Days delivery of Royalty Gas, upon written approval of the Commissioner, in the Commissioner's sole discretion, Buyer may decrease the principal face amount of the Letter to an amount equal to the estimated price of 180 Days delivery of Royalty Gas.

6.2 Security Contract. Upon approval by the Commissioner, in the Commissioner's sole discretion, as alternative security to the Letter required in Article 6.1, Buyer may deliver to the State: (1) an irrevocable stand-by letter of credit in the principal face amount estimated by the Commissioner to be equal to the value of Royalty Gas to be delivered by the State to Buyer during the 90 Days immediately following the Day of First Delivery; and (2) an irrevocable contract between a major oil company ("Promisor") and Buyer for the direct benefit of the State, in which the Promisor agrees to assume full liability for Royalty Gas upon notice that Buyer is in default of this Agreement ("Security Contract"). The 90-Day letter of credit shall be subject to all the terms and conditions of Article 6.1. The Security Contract shall designate the State as intended third-party beneficiary and shall be in effect by the Day of First Delivery. It shall provide that upon written notice by the Commissioner to Buyer and the Promisor that Buyer is in default of this Agreement, the Promisor shall immediately assume full liability for purchase, transportation, and disposal of a minimum of 90 Days deliveries of Royalty Gas from the Point of Delivery. It shall provide the State a direct right of action against Buyer and the Promisor, jointly and severally, to enforce the Security Contract, regardless of whether the State takes action to enforce this Agreement against Buyer. It shall also provide that the Promisor has no right of action against the State and may not assert against the State any defense it may have against Buyer under the Security Contract.

6.3 Special Security. [Reserved for additional or other security a Buyer may offer.]

6.4 Other Security. The Commissioner may, in the Commissioner's sole discretion, require such other or additional security from Buyer as the Commissioner considers adequate to protect the State's interest. [The State may require (1) an escrow account of \$___ per Mcf to pay for adjustments or (2) that the Letter be maintained in an amount sufficient to pay for adjustments after the State stops delivering Royalty Gas.]

ARTICLE VII MEASUREMENTS

7.1 Measurements. Procedures used for metering and measuring the Royalty gas shall be in accordance with the procedures in effect in the Units.

ARTICLE VIII EFFECTIVE DATE AND TERM

8.1 Approval. This Agreement is subject to approval under Alaska Statute 38.06.055. If all approvals required by AS 38.06.055 have not been obtained by August 31, 2002, either Party may terminate the Agreement on 30 Days notice. If an Open Season for the Gas Pipeline is not completed by December 31, 2004, either Party may terminate this Agreement on 30 Days notice.

8.2 Term. [The term will be determined by the proposal.] Termination of this Agreement shall not relieve either party from any expense, liability, or other obligation or any remedy that has accrued or attached prior to the date of termination. For Royalty Gas actually delivered under this Agreement, termination of this Agreement shall not relieve Buyer of its obligation to pay all production month invoices, initial adjustments, subsequent adjustments, and interest, and, where applicable, penalties, costs, attorney fees, and any other charges related to the Royalty Gas actually delivered. The provisions of Article IV shall survive termination of this Agreement.

8.3 No Delivery of Royalty Gas. This Agreement shall terminate on July 31, 2012 if the Gas Pipeline is not in service by that date or if no Royalty Gas has been delivered by that date.

8.4 If the conditions set forth in Article 8.1 fail and this Agreement is not approved by August 31, 2002, or is terminated under Article 8.1, or if the Gas Pipeline is not in service by July 31, 2012, the State shall return to the Buyer the bonus paid by the Buyer, without interest.

ARTICLE IX DEFAULT OR TERMINATION

9.1 Default.

9.1.1 Events of Default. The Commissioner may, in the Commissioner's sole discretion, suspend, terminate, or reduce the State's obligation to tender, deliver, and sell Royalty Gas to Buyer, and may exercise any one or more of the rights and remedies provided in this Agreement, or at law, if any one or more of the following events of default occur:

- (i) Buyer fails to pay in full any sum of money owed under this Agreement within two business Days after the State gives Buyer notice that payment is past due and has not been paid;
- (ii) Within five Days after written request from the State, Buyer fails to provide written assurances satisfactory to the State of its intention to perform its obligations under this Agreement and evidence or assurances of transportation arrangements under Article 3.9;
- (iii) There is a substantial change in Buyer's financial condition, business operations, agreements, or property or ownership that may affect Buyer's ability to perform its obligations under this Agreement, and within five Days after a request by the State, Buyer is unable or unwilling to provide the State with adequate assurance of continued performance;

- (iv) Buyer fails to perform any of its obligations under this Agreement, and cannot cure the non-performance or the non-performance continues for more than thirty Days after the State has notified Buyer of its non-performance;
- (v) Any representation or warranty made by Buyer in this Agreement is found to have been materially false or incorrect when made; or
- (vi) Buyer fails, or is unable for any reason (including reasons beyond Buyer's control), to maintain the [security letter of credit] [other security] required under Article VI, regardless of Buyer's willingness or ability to perform any other obligations under this Agreement.

9.1.2 Default by Inability to Pay. Buyer shall immediately provide the State with written notice if Buyer is unable to pay any of its debts when due or is otherwise insolvent. Upon such notice from Buyer, or if the State independently determines that Buyer is unable to pay any of its debts when due or is otherwise insolvent, the State's obligations to deliver and sell Royalty Gas to Buyer shall automatically and immediately terminate without any requirement of notice to Buyer or other action by the State. Within thirty Days after termination under this Article 9.1.2, the State shall have the right, upon written notice to Buyer, to reinstate all of the State's and Buyer's obligations under this Agreement retroactive to the date of termination.

9.2 State's Remedies. If Buyer defaults under this Agreement, in addition to all other remedies available to the State under this Agreement or at law, the following remedies shall be available to the State in the Commissioner's sole discretion.

9.2.1 Buyer's Obligations Become Due. All monetary obligations Buyer has accrued under this Agreement, even if not yet due and payable, shall immediately be due and payable in full.

9.2.2 State May Dispose of Royalty Gas. The State may dispose of some or all of the Royalty Gas to third parties. If the State exercises this remedy, regardless of whether this Agreement is terminated, Buyer shall be and remain liable to the State for the amount of the difference between the Price for the Royalty Gas under Article III and the actual price the State receives from disposition of the Royalty Gas to third parties.

9.2.3 Indemnification for Loss. Buyer shall hold the State harmless and indemnify it against all liability, damages, expenses, attorney's fees and costs, and losses arising out of Buyer's default, termination of the State's obligations, and disposal of the Royalty Gas to third parties. Additionally, if Buyer defaults in the payment of the Base Price, Buyer shall pay the State 100% of costs and attorney fees incurred by the State in pursuing payment of the Base Price, regardless of whether litigation is commenced and regardless of whether legal services are provided by the Attorney General's office or private counsel.

9.2.4 Damages for Breach of Special Commitments. If a Buyer offers Special Commitments, the Buyer should propose liquidated damages payable upon its failure to perform those Special Commitments.

9.2.5 Other Rights and Remedies. The State shall have the right cumulatively to exercise all rights and remedies provided in this Agreement and by law, and obtain all other relief available under law or at equity, including mandatory injunction and specific performance, except that Buyer's Special Commitments shall not be subject to specific performance.

9.3 Limitation of Buyer's Remedies. If the State breaches or defaults in any of its obligations under this Agreement, Buyer shall not obtain a temporary restraining order or preliminary injunction preventing the State from disposing of the Royalty Gas subject to this Agreement.