

ALASKA LEGISLATURE SPECIAL COMMITTEE / SUBJECT FILE 8672

1210 SCOMM 4-6: HOUSE SPEC. COMMITTEE ON OIL AND GAS 1985-86

SCOMM 46: HOUSE SPECIAL COMMITTEE ON OIL AND GAS, 1985-1986

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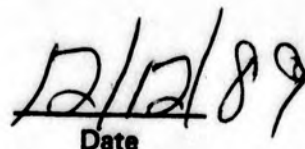


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Alaska State Legislature

House of Representatives

HOUSE SPECIAL COMMITTEE

ON OIL AND GAS

Pouch V
State Capitol
Juneau, Alaska 99811

MEMORANDUM

To: Rep. Ben Grussendorf,
Speaker of the House

From: Rep. Mike Davis, Chairman
House Special Committee on Oil and Gas

Date: January 18, 1985

Re: Committee expenses during session

The House Special Committee on Oil and Gas will be addressing several issues this session which are of major consequence to the State of Alaska. These issues include the clarification of state policy regarding the disposition of royalty oil, oil and gas tariff and taxation structures, the resolution of state and federal boundary conflicts along the Outer Continental Shelf, and the possibility of gaining an exemption from the Export Administration Act that would allow for the foreign export of Alaskan crude oil.

This committee also expects to conduct either meetings or hearings regarding litigation in which the state is presently involved, upcoming royalty oil contracts, and the export potential of Alaskan natural gas.

The attached budget outlines the funds required in order for this committee to adequately address these issues.

HOUSE SPECIAL COMMITTEE ON OIL AND GAS

14th Legislature, First Session Budget

Supply

\$ 7,000

Items included in this line item are telephone, telex, and copying costs, miscellaneous office supplies, a typewriter, and a personal computer with appropriate software.

Contractual

\$30,000

These funds are for consulting fees, to be used in hiring consultants to make recommendations concerning certain oil and gas issues.

Travel

\$20,000

Travel funds would allow the committee to hold hearings in major Alaskan communities, such as Anchorage and Fairbanks, provide for a trip to Washington DC, if necessary, and allow for expert witnesses to be brought in to provide testimony before the committee.

Total budget request: \$57,000

ARTA ENERGY INSIGHTS

Pacific Oil Insights

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ALASKA GOVERNMENT AFFAIRS.

Number 5

December 1984

DISPOSITION OF ALASKA ROYALTY OIL AND OTHER STATE PETROLEUM-POLICY ISSUES

By Robert L. Williams, Jr.

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DISPOSITION OF ALASKA STATE ROYALTY OIL

By Robert L. Williams Jr.

EDITOR'S NOTE: INTRODUCTION, SUMMARY AND CONCLUSIONS

By the time subscribers receive this issue of *Insights*, the State of Alaska will have conducted its second auction of North Slope royalty oil. The following article by Robert L. Williams reviews the background to this sale, and the considerations that led the state government to adopt the auction method for marketing about half of its one-eighth share of the crude-oil produced from the Prudhoe Bay and Kuparuk River fields. He also surveys the fiscal risks the State incurs in selling its oil independently, and the likely impact of the sale on the level and structure of West Coast crude-oil prices. *For additional background relevant to this issue, we recommend that the reader refer to Pacific Oil Insights No. 2, "ARCO and its Critics: The North Slope Crude-Oil Transfer-Price Controversy."*

Alaska's share of North Slope production is currently about 200 thousand barrels per day, equal to almost one-tenth of PAD District V (the West Coast) crude-oil demand. Together with severance tax revenues from North Slope oil, these royalties constitute the bulk of state and local revenues in Alaska, and support about half of Alaska's civilian economy. *The economic role of North Slope crude-oil production in Alaska is elaborated in a Supplement to the current issue of Insights, "Alaska's Petroleum-Based Economy," a chapter by Arlon R. Tussing in Alaska Resources Development: Issues of the 1980s, edited by Thomas A. Morehouse.)*

Alaska North Slope oil and gas lease contracts allow the State to choose between two methods of collecting its royalties, "in-value" and "in-kind". With an in-value taking, the State allows the producing companies to sell the royalty oil to their refining affiliates or other refiners as if it were their own, and to pay the State a cash royalty based on its "netback" value --- the refinery price of the crude oil less tanker and pipeline transportation costs. Alternatively, the State may take the oil in kind, in order to seek a higher price than the netback values declared for royalty purposes by the producers, or in order to promote local refining or petrochemicals production.

Since crude oil began to flow through the Trans-Alaska pipeline in mid-1977, the State's royalty-oil disposition policy has been an issue of political debate. The easiest and safest course would obviously have been to take all royalties in value. The State would still have had an interest in auditing the destination prices and transportation deductions claimed by the the producers in order to assure itself royalty and tax payments were based upon the full netback value, but the administrative tasks in-value taking imposes on state officials are minimal, and marketing risks nil.

The impulse to take at least some of the State's royalty in kind for "in-state" processing was nevertheless compelling. Almost every sectoral interest and political faction in Alaska supported the idea of using royalty-oil sales to promote construction of local refineries and and petrochemical plants. The promoters of such facilities claimed that an assured supply of feedstock was a precondition for financing and that royalty oil was the only credible source of such a long-term commitment. In the scarcity atmosphere of the 1970s and early 1980s, such claims were persuasive; and so long as the sales contracts for in-kind royalty oil to local processors provided a price equal to the price basis for in-value royalties, the state Treasury would be no worse off with an in-kind taking. Sale of royalty oil to the sponsors of new plants at the in-value price led inexorably to sales at that price to

support expansion of existing refineries; "fairness" then demanded that all Alaska refiners receive state royalty oil on similar terms. This process has now resulted in commitment of about half of the North Slope royalty oil to in-state processors.

By 1983, the preference for in-state processing had becoming controversial. Critics alleged that new sales to Alaska refiners would not induce any industrial development that would not otherwise occur, and that they had not in the past led to lower gasoline and fuel-oil prices for Alaska consumers. Such sales, it appeared, only sacrificed the premium above in-value prices the State might have collected by selling royalty oil to the highest bidder, local or otherwise. It was obvious, moreover, that there were indeed customers for North Slope oil at prices exceeding the in-value price. Major West Coast refiners, including Shell and Texaco, had already approached the State with offers to pay more and, for all one could tell, their offers were not the best available.

The Williams article explains why some West Coast refiners would be willing to bid more than the in-value price. That price, as received by the State, reflects a weighted average of North Slope netback values from all destinations. Top bidders at a royalty-oil auction, on the other hand, would tend to be West Coast refiners, who could offer more than the average netback price because they had to bear less than the average of transportation costs. This line of reasoning is valid as far as it goes. But the most vehement critics of existing state policy failed to recognize that their position depended on the assumption a state auction of royalty oil would leave the in-value price (and the West Coast netback price that is one of its components) unchanged. Williams discusses two reasons an arms-length royalty-oil sale would cause the in-value price to fall, which he characterizes as the "displacement" effect and the "competitive" effect, respectively, of a state royalty-oil sale.

"Displacement". First, because the high bidders would be West Coast refiners, and any such sale of royalty oil would tend to push some producer sales of North Slope oil from the West Coast into the Gulf/East Coast markets. If such a displacement tendency were 100-percent effective, that is, if the producers (principally Sohio) simply made way for the additional sales of royalty oil on the West Coast by diverting exactly the same amount of their own oil, the State auction would have no effect on prices at West Coast refineries, or on the netback prices reported by the producers for shipments to the West Coast. The displacement of producer sales would nevertheless change the mix of destinations on which the in-value price depended. As a result, the State's revenue per barrel from any royalty still taken in value, from existing royalty-oil sale contracts tied to the in-value price, and from severance taxes based on netback prices in producer sales would all be reduced. In order to capture more revenue from a direct sale of royalty oil, therefore, that sale would have to be at a price substantially higher than the in-value price. The premium required to offset the maximum impact of displacement can be calculated with reasonable confidence: In the Appendix table to Williams' article, we have estimated the necessary premium above the in-value price to be about 50 cents per barrel.

"Competition". The competitive effect of a state royalty-oil sale is more conjectural, but possibly far more serious than displacement from the standpoint of State revenue. To the extent that Sohio and other producers (including California producers) do not voluntarily reduce their own crude-oil shipments into District V to make way for increased royalty-oil sales, intensified competition for this market will cause crude-oil prices there to fall relative to Gulf/East Coast prices. The higher netback price for West Coast sales is an anomaly, preserved largely by Sohio's restraint in not maximizing its own sales into the more lucrative market. In a fully competitive domestic oil market, there would be only one price for crude-oil at Prudhoe Bay, reflecting the netback from U.S. Gulf Coast markets. A State royalty-oil auction, by weakening both Sohio's market power in District V and Sohio's

incentive to use that market power to support the West Coast price, undoubtedly adds to the forces pressing prices downward, in the direction of such a competitive equilibrium. The potential price reduction is several times the premium the State would have to obtain to offset the pure displacement effect.

The Alaska State officials who organized the royalty sales are clearly aware of both effects. They have established a minimum-bid price for the December auction that does not depend on the weighted-average in-value price, and which is high enough to offset the maximum impact of displacement as such. They have decided to gamble, however, that the State's appearance as an independent crude-oil marketer in District V will not collapse the existing two-tier price structure. In our judgment, this is probably a fair gamble, but for a reason that offers them little comfort: Competition among Alaska and California crude-oil producers is bound to intensify dramatically over the next two or three years no matter what the State does with its royalty oil.

With the development of new fields on the North Slope (Kuparuk, Milne Point, and Endicott), continuing gains in thermally enhanced recovery of California heavy oil, and a huge upward leap in California offshore production, the West Coast "surplus" will swell and Sohio's share of that surplus will fall from nearly one hundred percent to perhaps one-third. Under these circumstances it is hard to imagine how the existing two-tier pricing structure can long survive. The smaller the difference in North Slope prices between California and Gulf Coast netbacks, the less it matters how to Alaska's treasury how the State markets its oil.

The December sales will have terms of only six months to one year. Any bid above the base price will lock in prices that more than offset any loss of revenue that results from the impact of displacement on the in-value royalty price. It is still conceivable that the sale will accelerate the fall in West Coast oil prices relative to those at the Gulf, and that the net effect over a period of more than one year will be some net loss in state petroleum revenues. Even if this happens, however, no one will ever be able to prove, much less measure, the State's role in the collapse. If, on the other hand, the two-tier price system does not collapse instantly, Alaska's short-term gain will be both material and demonstrable over the term of these particular sales. As we remarked above, the auction is a good gamble --- politically and financially --- but a gamble nonetheless. (. . . by A.R.T., December 10, 1984)

The author, Robert L. Williams Jr. has served in several senior staff positions in the executive and legislative branches of the Alaska State Government.

Part I

THE ALASKA ROYALTY OIL AUCTION

A. BACKGROUND

The State of Alaska's North Slope hydrocarbon leases grant the State two options for disposing of its 12½-percent royalty share in the produced oil and gas. The State may elect to have the producers maintain possession of the oil, market it

as their own, and pay the State an "in-value" price for the royalty volumes sold. The formula for the in-value price uses the producers' own sales data, netted back to the wellhead.

Alternatively, the State may elect to take any portion of its royalty allotment "in kind" --- that is, it may notify

producers of its intention to accept physical delivery of crude oil. Since production began in 1977, Alaska has gradually increased its in-kind takings of North Slope royalty oil. Table 1 lists the existing royalty contracts for which the State is taking hydrocarbons in kind.

The State intends to sell an additional 90 thousand barrels per day (mbpd) under 6-month and one-year contracts in an auction scheduled for December 11, 1984. If sales are consummated, Alaska will have committed through September 1985 all but about 26 mbpd of combined Prudhoe Bay and Kuparuk royalty volumes at the current average North Slope production rate of about 1.62 million barrels per day (mmbpd). And from October 1985 through March 1986, about 41 mbpd will remain uncommitted.*

The State is offering relatively short terms for the auction contracts partly to ensure that the oil can be made available for Alaska processing if and when growth in demand so warrants. In addition, the State has chosen to take in perpetuity a minimum volume of its royalties under the in-value terms of the leases. Absent in-value producer payments, the local refiners who purchase royalty oil under existing contracts (with price terms keyed to the State's in-value receipts) would have no basis upon which to determine the payments due. Moreover, the absence of in-value royalty data would make the assessment of severance taxes more difficult.

Instead of using an auction, the State has until now negotiated most of its sales for both Cook Inlet and North Slope royalty oil with companies who operate or proposed to operate refineries in Alaska.** The stated purpose of such sales was to induce economic growth. Negotiated sales were not consummated, however, under any circumstance where the

prospective purchaser required a direct subsidy in the form of a price lower than the State's opportunity cost --- the revenue it would have received under the in-value royalty option.

By the late 1970s, State officials were beginning to suspect that Alaska refiners and other companies who marketed petroleum products within Alaska might be willing to pay a premium above the in-value price in exchange for the security implicit in a supply agreement of a year or more. These officials thus believed Alaska could have its cake and eat it too; the disposition of royalty oil would still foster local economic activity, but it might also bring in more revenues than producer in-value payments would otherwise contribute.

In December 1980 the State of Alaska conducted its first competitive sale of royalty oil. The sale was timed to take advantage of the tight market and the nervousness of refiners about reliable crude-oil supplies that existed after the Iranian oil crisis. Spot prices for ANS crude were then considerably higher than term contract prices, and companies bid premiums well above the in-value price for the 85 mbpd offered. The State established a base price for this auction that, in itself, was higher than the average in-value payment. Bidders then offered premiums in excess of \$3 per barrel.

Shortly after the sale, however, the spot market for ANS oil collapsed. Successful bidders thus were stuck with an obligation to buy some uneconomically high-priced oil. Energy Cooperative Inc. defaulted on its payments and went bankrupt during the term of its contract. Alaska Petroleum Company refused to take its committed volumes. Worse yet, a major purchaser under a negotiated contract (Alpetco) refused to take its portion of royalty deliveries.

This turn of events forced the State into emergency negotiations with field operators ARCO and Sohio. Unlike the North Slope producers, the State has no facilities in Valdez to hold its inventories; it has no tankers; and it has no personnel in the oil trading business. And because

* The State will auction: 50 mbpd of Prudhoe Bay oil under one-year contracts; and 25 mbpd of Prudhoe Bay oil plus 15 mbpd of Kuparuk River oil under six-month contracts.

** See "An Overview of Alaska's Royalty Oil Sales", Geoffrey Haynes, Alaska Department of Natural Resources, 1982.

the leases prevent Alaska from instantaneously reverting to the in-value form of royalty disposition, the defaults left the State in a terrible pickle. Today, the State is still trying to collect about \$60 million in alleged back payments from Charter Oil Company (parent of Alpetco), but the prospects for recovery are slim because Charter is now operating under the protection of bankruptcy laws.

B. THE ROYALTY-OIL DEBATE

The State will again undertake a competitive sale in December 1984. Eligibility is not restricted to companies who commit to processing the oil within Alaska. All three of the state's refiners have, instead, already entered into negotiated sales for royalty oil. (See Table 1.)

This is the first sale of North Slope royalty oil in which prices are not directly linked to the in-value price. To protect itself against default, the state undertook a "prequalification process." Fourteen companies passed this screening, which included "demonstration of financial ability and management ability" and the posting of 60-day letters of credit to cover the amount of the premium for thirty days.

Bidders also must agree to a "put-call" option in the auction contracts. Modelled after the federal Elk Hills contract, this term grants the government the right to boost deliveries immediately and without notice by up to 20 percent beyond contracted levels for up to thirty

days. Beyond the initial thirty days, the State plans to cover a default by activating its "back-up" contracts, in which parties have agreed to accept royalty volumes upon thirty-day notice.

The auction follows two years of heated debate between the Sheffield Administration and legislators over approval of royalty oil contracts with Tesoro-Alaska Petroleum, Inc. and Chevron USA. Both companies operate refineries on Alaska's Kenai Peninsula south of Anchorage.

The new Chevron contract negotiated by the Department of Natural Resources commits 18 mbpd for a term of 11 years (subject to pro-rata reductions if a decline in North Slope production restricts the available supply). The new Tesoro contract commits 26 mbpd, with a similar 11-year term.

Tesoro argued that its contract would serve as financial support for a \$90 million expansion and upgrade of its Alaska plant. The company maintained that the new hardware was vital for accommodating a switch in feedstock from the light, sweet (40° API, 0%-S) crude oil of Cook Inlet, where production was fast dwindling, to the medium-gravity, sour (27°, 1%-S) crude produced on the North Slope. Tesoro had, in fact, been supplementing its Cook Inlet feedstocks with Indonesian crude of similar grade for a number of years.

In some respects, the controversy over the proposed sales came as a surprise. The contracts were conceived under the previous Hammond administration; Governor Sheffield introduced them for requisite legislative approval pretty much as clean-up legislation.

Then too, the previous policy encouraging Alaska processing of royalty hydrocarbons had enjoyed support from practically every political faction. It was embedded in statute and had been reaffirmed on numerous occasions by the Alaska Royalty Oil and Gas Development Advisory Board and by the cabinet members in charge of management of royalty oil and gas.

Table 1
State of Alaska
ANS In-Kind Royalty Oil Contracts
(in barrels per day)

Company	Quantity	Term	Price
Tesoro	39,765	1/83 to 1/95	In Value
	26,000	10/85 to 1/95	In Value + \$0.35
Mapco	35,000	11/79 to 12/03	Exhibit B
Chevron	18,000	5/84 to 1/95	In Value + \$0.30
GVEA	5,000	7/84 to 6/85	In Value + \$0.30

Source: State of Alaska, Department of Natural Resources

Tesoro already had one long-standing contract with the State for Cook Inlet oil, and the price terms in the existing contract were substantially less demanding than those proposed in the new sales agreement. Both Tesoro and Chevron, moreover, were considered "good corporate citizens."

What, then, caused the fuss? The contracts had been introduced in 1983, at a politically inopportune time. Governor Sheffield was being excoriated by political opponents over a Dallas fund-raising affair at which oil companies contributed about \$150,000 to pay off his 1982 campaign debt. As it turned out, Tesoro was one of the contributors. And the ensuing debate revealed that Charter Oil Company (which the State has accused of \$60 million in damages for royalty oil not taken in 1981) had acquired a significant interest in Tesoro.

Beneath the political controversy, however, was a substantive issue. Legislative opponents maintained that the price provisions of the contracts --- whether or not they gave the State a better deal than previous contracts --- still contained a hidden subsidy. They maintained that the in-value price term upon which the contracts were based was no longer a responsible approach for ensuring that the state received a fair return on its resources.

The in-value price specified in all of the State's North Slope leases represents a weighted average "netback" price (refinery prices less transportation costs) declared by the various producers. It is therefore also a weighted average of netbacks from West Coast refineries and those East of the Rockies (EOR). To the extent that lower netback values from the Gulf Coast and East Coast sales are averaged into the in-value price, the overall weighted average tends to be lower than the West Coast netback.

Representative John Cowdery, co-chairman of the House Oil and Gas Committee, led the attack. In a letter published in a September 1983 issue of the Anchorage Daily News, Cowdery said,

Geographically, Alaska is on the West Coast. Therefore, the price of oil sold in Alaska should be based on the West Coast market value and not on an average of the price of oil sold on the West Coast and Gulf coast.

Cowdery's argument was reinforced dramatically in January 1984, when Shell posted a price for ANS oil delivered to Pump Station No. 1 at the inlet of the Trans Alaska Pipeline (TAPS). Although Shell's posting cannot be compared directly with Alaska's long-term royalty contracts because of differences in term, volume, and the ancillary benefits of "in-state use", the \$18.25 posted price was nevertheless about a dollar more than what the State could expect to get under the Tesoro and Chevron contracts.

Shell's posting was a historic first for ANS oil, and the timing of the announcement exacerbated the problems for the Sheffield administration in seeking legislative approval of the Tesoro and Chevron contracts. More importantly, however, it called into question the State's longstanding policies for pricing royalty oil sales --- policies that predated Sheffield's tenure in office.

The contracts were finally approved in May 1984. But in the meantime, they had been changed to include premiums above the in-value price. Tesoro agreed to pay a premium of 35 cents per barrel and Chevron agreed to pay 30 cents.

These premiums, nevertheless, still offered the State a lower price than it could get if it simply sold to Shell at the posted price. Price reopeners (after six years for Tesoro, and after 2 years for Chevron) were therefore included in the contract amendments.

An implicit quid pro quo in the legislature's approval of the royalty contracts was a commitment by the administration to auction the volumes of royalty oil that remained uncommitted. Shell's posting had proved that the State was not in fact getting top dollar for its resources. Alaska's final increment of its ANS royalties (at least over the short-term) would thus be dedicated to this end.

But the story does not end here. This auction will make Alaska the second

or third biggest arms-length seller of crude oil on the West Coast. The sale will thus materially realign the players and the placement of North Slope crude oil on the West and East Coasts. It is likely, as a result, to affect the State's oil-tax revenues and its receipts under other royalty agreements keyed to the in-value price. Finally, it is just one of several already substantial forces that threaten to erode the "two-tier price structure" which in itself makes West Coast sales unusually attractive for ANS producers.

C. NETBACK PRICING AND THE TWO-TIER PRICE STRUCTURE

In the Lower-48 states, refiners have typically "posted" the prices they are willing to pay for crude oil of a specified grade and quality produced from a particular field. Posted oil prices thus vary from field to field according to such considerations as distance to a refining center, sulfur content of the oil, and API gravity. Posted prices also change from time to time, according to world-wide aggregate supply and demand for feedstocks and finished petroleum products.

In competitive markets like the U.S. Gulf Coast, where demand is elastic and there are numerous buyers and sellers, postings have tended to rationalize themselves around the landed price of Saudi Arabian "marker" crude, with appropriate adjustments for location and quality. Postings within any particular field by different refiners, therefore, rarely have demonstrated a price spread, except for short periods of market adjustment.

Prior to Shell's January 1984 posting, values for ANS crude oil at the wellhead had never been established explicitly by "posting". Nevertheless, because calculation of producer obligations with respect to state and federal taxes and in-value royalties depended upon the measurement of ANS wellhead values, governmental agencies, the oil companies, and a host of lawyers had attempted to make an exacting science of such calculations.

Values for ANS crude oil have instead been based on a netback approach.

Each North Slope producer determines a downstream value for its crude oil based on a transfer price, exchange agreement, or third-party sale. From this downstream value, they deduct tanker charges, the TAPS tariff, and a portion of the field costs. What is left constitutes the netback value or wellhead price of North Slope crude oil.

Except during an interval in 1979 and 1980, when federal price controls constrained netback values, the reported netback value of ANS crude sold on the West Coast has been consistently higher than prices reported for Gulf and East Coast sales of the same supply. Table 2 shows a difference in netback values ex-

Table 2
Delivered Prices of ANS Crude
(in \$ per barrel)

	West Coast	Gulf or East Coast	West Coast Discount
7/83	\$25.32	\$27.50	\$2.18
8/83	25.45	27.87	2.42
9/83	25.65	28.04	2.39
10/83	25.71	27.90	2.19
11/83	25.73	27.93	2.20
12/83	25.73	27.89	2.16
1/84	26.05	28.05	2.00
2/84	25.57	27.87	2.30
3/84	25.59	27.91	2.32
4/84	25.49	27.93	2.44
5/84	25.64	27.94	2.30
6/84	25.70	28.04	2.34
7/84	25.81	27.45	1.64
8/84	25.63	27.92	2.29

Source: State of Alaska, Department of Revenue, 12/84.

Table 3
Disposition of ANS crude oil by PADD
(in thousands of barrels per day)

	PADD V (West Coast)	PADD I-IV (Gulf and East)	US Territories Caribbean	Total
7/83	843	780	117	1,740
8/83	812	634	114	1,560
9/83	898	631	121	1,650
10/83	792	780	117	1,689
11/83	914	674	110	1,698
12/83	963	605	59	1,627
1/84	898	598	117	1,613
2/84	887	677	175	1,739
3/84	998	621	58	1,677
4/84	1,031	418	172	1,621

Source: Pacific West Oil Data, 14621 Nordhoff Ave, Suite 1-C, Panorama City, CA 91402, compiled from federal sources

ceeding two dollars in recent months. This phenomenon has been dubbed the two-tier price structure.* It reflects a peculiarly segmented market for ANS oil whereby netback prices depend on sales

Table 3 shows the disposition of ANS oil in recent months. It is noteworthy that the surplus steadily dropped (from about 900 mbpd to about 600 mbpd) over the most recent 10-month period for which data is available. Placement of ANS on the West Coast has increased primarily because of increased refinery runs (which, in turn, reflect increased regional demand), but the surplus still remains substantial.

Under a competitive pricing model, a surplus of the magnitude shown in Table 3 would tend to drive ANS prices on the West Coast down. If there were a large number of oil producers on the West Coast and fully competitive markets, wide variances in ANS netback values would never have developed. Each producer would have found it profitable to market its crude where the netback was greatest.

If, for example, buyers on the Gulf Coast and West Coast were both willing to pay \$27 for ANS crude delivered to their refineries, producers would prefer West Coast placements; the smaller transportation cost would result in a higher netback at the wellhead. The attractiveness of the West Coast price would not last for long, however, as sellers offered discounts to capture an increased share of this more lucrative market. Such discounting would continue until there was little difference between the netback values of West and Gulf Coast sales.

This is not, however, what happens. The fact that Sohio (which owns half of Prudhoe Bay oil production, less royalties) has a net production exceeding the District V crude oil "surplus" means that Sohio alone determines the level of crude-oil prices on the West coast, whether or not the company wants to exercise such market power, by deciding how to divide

its own production between District V and Gulf Coast markets. Under these circumstances, it would have been surprising indeed if Sohio had chosen to compete so aggressively for West Coast sales that its own and everyone else's ANS netback price from the West Coast was driven down to the level it would reach in a perfectly competitive market, namely, equality with the Gulf Coast netback.

Although the market for ANS crude is far from perfectly competitive, competition has had an effect. Increased production on the West Coast, the prospect of recent finds, and ARCO's aggressive marketing effort to capture a larger share of the region's product market have undermined Sohio's ability to maintain the two-tier price structure. With a transportation differential of about \$3 or \$4 per barrel between Gulf and West Coast markets, a netback differential in the range of only \$2 does suggest the workings of downward price pressures.

The State of Alaska's December 1984 royalty auction will surely strengthen the already powerful forces eroding the two-tier price structure, perhaps by introducing wholly new players who will vie for limited West Coast sales. As a 12½-percent owner of North Slope oil, the State has a lot to lose if the two-tier price structure collapses and the West Coast netback falls to the level of Gulf Coast returns. How big is the risk that the auction will trigger a structural collapse, and are there other financial losses that may accrue from such a sale?

D. THE VALUE OF ROYALTY OIL

Unless the State of Alaska notifies a producer of its intent to take physical delivery of all or a portion of its royalty volumes, that producer is responsible for marketing the State's share of oil. In turn, the producer must reimburse the State in accordance with the in-value price terms of the North Slope leases.

To determine the in-value price, each producer calculates a netback price based on the weighted average of sales values at the point(s) of destination, less transportation and field costs.

* The origin and dynamics of this two-tier system is explained in *Pacific Oil Insights* No. 1, "ARCO and its Critics".

Such filings, to date, have demonstrated higher wellhead values for producers who report that most of their sales occur on the West Coast. ARCO's transfer pricing system, however, is the notable exception. Regardless of the actual locations of its ANS deliveries, ARCO imputes a destination value for ANS crude oil from the posted price of West Texas Sour delivered to Gulf Coast refineries, and this is the value it reports to the State. ARCO's adoption of this technique incited a furor which, in September 1983, led to an inquiry by Alaska's Senate Resources Committee on the matter of ANS sales and in-value royalty reports.**

Exxon told the committee that the company was then marketing about 350 mbpd of ANS crude oil, which included about 21 mbpd of royalty oil. Exxon delivered about 100 mbpd to its own West Coast refineries. The remaining 250 mbpd were shipped east: 200 mbpd went to the Gulf and the rest was delivered on the East Coast.

But even the eastern shipments of ANS crude were sold mostly to Exxon's refineries. Only ten percent of Exxon's entire ANS production was sold in arms-length transactions. In calculating netback values for the 90 percent of its production destined for intracorporate sale, Exxon therefore must impute a delivered value. The company assumes an ANS price equal to the prices of other crudes delivered to Exxon's various refineries through third-party sales and purchases. The imputed transfer price between Exxon's production unit and its refineries therefore varies according to location.

Of all the ANS producers, Sohio controls the biggest share. Sohio told the Senate committee that it was marketing about 600 mbpd of its own oil, plus about 41 mbd of Alaska's royalty share. The company delivered about 40 percent (240 mbpd) of the total to West Coast purchasers. The rest was going to the Gulf Coast and the Caribbean.

** See the Summer 1983 issue of *Pacific Oil Insights*, "ARCO and its Critics: The North Slope Crude-Oil Transfer-Price Controversy"

Sohio, however, was running less than two percent of its ANS oil through its own refineries located in Ohio and Pennsylvania. The company's reports to the State of Alaska thus included an ANS wellhead value that was based on its third-party sales, and which explicitly incorporated the two-tier price structure.

Unlike Exxon and Sohio, Arco's method for imputing (and reporting to the State) the wellhead value of its ANS production does not result in a two-tier price structure. The company maintains that there is only one value for ANS oil. ARCO's witnesses told the Senate Committee that the company begins its netback computations with the posted price of West Texas sour crude --- the most comparable grade for which substantial volumes are traded at arms-length in the Gulf Coast market. ARCO then adjusts the West Texas price postings to account for slight quality differences with ANS crude, and to account for the added delivery charges of moving it to the point of competition on the Gulf Coast. ARCO did not provide data on the disposition of ANS crude because actual delivery points are irrelevant to its netback calculation.

Table 4 shows the netback values reported to the State of Alaska by ARCO, Exxon, Sohio, and selected other North Slope producers. Not surprisingly, ARCO has reported the lowest netback values. The minor ANS producers reported the highest values because they are able to place most (if not all) of their production on the West Coast.

The monthly figures in Table 4 do

Table 4
1984 Netback (Wellhead) Prices of ANS Producers by Unit
(in \$ per barrel)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
Arco	\$16.44	\$16.30	\$16.22	\$16.19	\$16.17	\$16.30	\$16.30	\$16.58	\$16.62
Exxon	16.28	16.24	16.44	16.62	16.48	16.35	16.38	16.56	16.92
Sohio	17.29	17.40	17.41	17.31	17.62	17.67	17.55	17.69	17.99
Mobil	18.81	18.80	18.98	18.76	18.92	18.92	19.10	18.92	18.91
Texaco*	18.10	18.10	18.10	18.10	18.08	18.08	18.10	18.08	18.08
Chevron	17.25	17.10	17.30	17.54	17.47	18.35	17.66	17.93	17.84
Wild Avg	16.84	16.88	16.93	16.91	17.02	17.03	17.00	17.18	17.41
Erb B	17.87	17.99	18.01	17.94	18.17	18.21	18.13	18.27	18.52
Shell Port	18.25	18.25	18.25	18.25	18.25	18.25	18.25	18.25	18.25

Source: State of Alaska, Department of Natural Resources and Shell

not reveal the range of sales data that each company uses to impute the ANS value. Nevertheless, it is clear that the State of Alaska's royalty (and severance tax) revenues are affected by the destination of ANS crude and by who is selling it.

Over the long run, these disparities will probably subside. The existence today of a two-tier price structure on the North Slope is fragile. Ultimately, a buyer's market on the West Coast will force ANS prices downward in that market. The spread between delivered West Coast and Gulf Coast prices for ANS will thus enlarge; but at the same time, the spread in wellhead values will diminish.

E. THE EXHIBIT B PRICING FORMULA

The calculation of in-value royalty payments turns out to be a lot more complicated than each company's computation of its weighted average netback price. The leases direct producers to pay the state an in-value price for royalties marketed based on the following:

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 to 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 grade and quality at the time such oil or gas is removed...

In 1978, the State of Alaska detailed its interpretation of the lease-pricing provisions in an exhibit prepared for a royalty oil sale. Through Exhibit B the State wished to ensure that revenues would be no less than they would have been if the state had continued taking the oil in value. According to the Haynes report (*op. cit.*), the intent of the North Slope leases as interpreted in Exhibit B was "to protect the state from an inefficient producer which sells a large percentage of its oil in the least lucrative market." The producers, however, maintain that the Exhibit B formula imputes an in-value price that is higher than the leases themselves dictate.

Despite the issuance of Exhibit B, the producers continued to pay in-value

state royalties according to their own interpretation of the leases. The State petitioned the Superior Court for a ruling. Despite some settlement, the case is still active under the title, "State of Alaska v. Amerada-Hess et al."

The outcome of the suit will have financial consequences in the hundreds of millions of dollars. In recent months, for example, the Exhibit B price has been about 50 or 60 cents higher than Sohio's in-value reports. The irony here is that while the revenues of all North Slope producers and the State of Alaska would plunge if the two-tier price structure collapsed, and while Sohio plays a pivotal role in maintaining that structure, Sohio could be liable for back royalty oil payments generated by its support of the very price structure that the State is attempting to exploit through Exhibit B.

F. THE AUCTION'S IMPACT ON STATE REVENUES

The successful bidders in the December auction will be those who are confident that they can place the oil on the West Coast --- where the higher netback price affords them an opportunity to offer the State a premium. Unless all of the awarded volumes go to bidders that already market ANS crude oil on the West Coast, some of the North Slope producers are going to find their West Coast market outlets diminished.

As a result, they will either have to send more of their oil to eastern markets (and suffer reduced overall netbacks) or they will have to offer price discounts to maintain their West Coast market share. In either case, the implications for changes in state royalty and tax revenues on the over 115 mbpd not sold in this auction are unfavorable.

The displacement of producer sales on the West Coast would result in a reduction in reported weighted average netbacks, and hence a reduction in in-value royalty payments. Severance taxes based upon the in-value reports would also decline, as would revenues flowing from prior royalty contracts keyed to in-value payments.

State officials are not unaware of these ancillary financial implications of the auction. For this reason, they have chosen to establish a "base" price for bidding premiums which will compensate (or overcompensate) for the loss in revenues that the displacement will cause.

The base price for the December auction represents the first instance in which the State will engage in an in-kind royalty oil sale that is not explicitly related to the in-value price reported by producers. It will also be the first time in which contracts do not hedge against a state win in the Amerada-Hess case that might otherwise compel producers to make back-payments on in-value royalties.

The base price for the December auction is \$17.92 per barrel for the 75,000 daily barrels of Prudhoe Bay crude and \$16.92 for the 15,000 daily barrels of the lower-valued oil from the Kuparuk River field. The contracts also provide that these base prices will move up or down with changes in the posted price of West Texas sour crude.

We were not able to obtain from state officials a detailed explanation of the genesis of this base price, but it is founded on the weighted average netback price reported by producers in May 1984, plus field costs, plus a tariff adjustment. It is noteworthy that the base price for Prudhoe Bay oil is only two cents less than the imputed Exhibit B price for May 1984, and 32 cents higher than the Tesoro contract, for example.

The base-price concept was first tested in July 1984, when the State solicited "back-up" bids for the December 1984 auction. Back-up bids were necessary six months prior to the auction for several reasons. First, the state wanted to ensure that in the event of default, other entities would be contractually committed to take the excess royalty volumes upon thirty days notice. These back-up contracts contained such provisions.

Second, the State did not want to be in a position of nominating in-kind deli-

veries of royalty oil in accordance with the schedule set forth in the North Slope leases without being sure that somebody would take the oil at a reasonable price. And yet if the auction were held six months prior to deliveries, price uncertainty might diminish buyer interest. The security of back-up contracts thus allowed the State to nominate royalty oil volumes in September, for delivery in April, and to hold the auction itself in December.

The base prices for the back-up bids are the same as the base prices for the December auction. These base prices proved to be 89 cents and 16 cents higher than the weighted average in-value prices the State received in the month prior to the solicitation (June 1984) for Prudhoe Bay and Kuparuk oil respectively. And because the alternative to the sale is continued in-value taking of 85 mbpd of the remaining 90 mbpd of royalty oil, the base price (even absent any premiums) offered the State about \$68,000 more in direct daily revenues, absent any major changes in relative price movements between in-value producer reports and the price of West Texas sour.

The base prices for the back-up bids nevertheless appeared to be well within the range of commercial feasibility. The Prudhoe Bay base price, for example, was 29 cents less than the June Exhibit B price. And it was a full dollar less than the in-value price reported by Mobil.

It is not surprising then, that several companies did respond to the State's solicitation with premium bids. (See Table 5.) Texaco offered the highest per-barrel premium: 38 cents. Mapco and Shell offered premiums of 35 and 25 cents respectively, but both conditioned their bids on changes in other contractual terms of sale. Only one bid (7 cents premium) was received for Kuparuk oil.

Even if the December auction fails to attract acceptable bids, these back-up bids (indeed, the base price alone) seems to ensure the State of revenues that more than offset the loss of severance taxes, in-value payments, and other royalty in-

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Editor, Natural Gas Insights: CONNIE C. BARLOW

come. The Appendix examines these potential revenue losses.

VI. THE AUCTION'S IMPACT ON THE TWO-TIER PRICE STRUCTURE

It appears that the only real financial risk to the State of the December auction is rather speculative, that is, the risk that the auction will exacerbate the price discounting already taking place on the West Coast or that it may, in fact, cause or accelerate the collapse of the two-tier price structure.

Under the worst of conceivable scenarios, West Coast netbacks could plunge to Gulf Coast levels as a result of the auction. State revenue losses would more than offset the auction's direct gains. If, for example, all producers had reported netbacks equivalent to Gulf Coast prices in June 1984, the state would have received \$318 thousand less in royalty and severance-tax revenues each day. This compares with a potential revenue gain from the auction itself of \$71 thousand per day at a zero premium over the base price, and \$156 thousand at a one-dollar premium, assuming the maximum displacement effect.

How big is the risk that this auction will trigger a structural price collapse? ANS oil constitutes the marginal supply on the West Coast. Although the 85 mbpd

of oil up for grabs is only about five percent of total ANS production and only about 3½ percent of West Coast refinery demand, even that amount of oil can effect real competitive pressures if it is in the hands of aggressive "outside" marketers.

Taxecon Associates, for example, told the state of Alaska:

*The partial breakdown in the two-tier price system in 1981 was precisely the period in which Alaska Oil Company was taking 75,000 barrels per day in state royalty oil under its scheduled-to-expire contract, and four of the six winners in the state's only competitive sale of royalty oil were forced to take delivery of their unwanted oil.**

Who among the producers has the most vulnerable markets? It is not Exxon. Exxon already delivers most of its ANS to the Gulf Coast; and the 100 mbpd that is placed in the West has a secure destination in Exxon's own refinery in Benecia, California.

ARCO's 320 mbpd of West Coast refining capacity is nearly sufficient to handle all of its ANS crude allotment. Many of the smaller ANS producers (Mobil, Getty, Chevron) have some West Coast refining capacity, relative to which their North Slope production is minor.

Of all the ANS producers, Sohio is probably the most vulnerable to competitive forces unleashed by the auction. Sohio has no West Coast refineries; all of its placements in this preferred market thus depend on successful negotiations with nonaffiliated firms.

But is the auction likely to present a threat to existing market arrangements and pricing? Eighty-five thousand barrels of reallocated daily production seems insignificant compared to the projected increase in overall North Slope production of almost 200 mbpd by 1987. Expanded Kuparuk production, as well as the onset of production from the Lisburne, Endicott, and Milne Point fields will account for this increase.

Then too, there may be a considerable increase in California offshore production by the end of the decade. The

Table 5
Competitive Back-Up Bids for the 1984
State of Alaska Royalty Auction
(in thousand barrels per day)

Company	Field	Quantity	Premium	Total
Tessco	Prudhoe	50,000	\$0.38	\$18.30
	Kuparuk	10,000	0.07	16.99
US Oil & Ref.	Prudhoe	5,000	0.15	18.07
Chevron	Prudhoe	30,000	0.10	18.02
Union	Prudhoe	10,000	0.00	16.92
Mapco*	Prudhoe	5,000	0.35	18.27
Shell*	Prudhoe	20,000	0.25	18.17

Source: State of Alaska, Department of Natural Resources -- Base price per barrel for Prudhoe Bay is \$17.92 and Kuparuk \$16.92. The weighted average of the bids is \$18.10 per barrel.

*Bids conditioned upon contract changes.

* Taxecon Associates, "Analysis of the Economic Effects of a Competitive Sale of In-kind Royalty Oil by the State of Alaska", June 28, 1984 (for the Alaska Department of Natural Resources).

October 15, 1984 issue of the Oil and Gas Journal, for example, projected production from California's offshore Point Arguello field alone topping 100 mbpd by 1987, increasing ultimately to a level in the vicinity of half a million barrels per day.

Increases in California production may be expected to back out ANS production directly. Economic efficiencies militate against anyone offloading tankered Alaska oil in California to the extent that it would force California oil to be loaded into tankers and shipped through the Panama Canal. If any of the contemplated transcontinental oil pipelines is built, however, and if local refiners resist taking expected deliveries of Exxon's

heavy offshore crude, increases in California production may not extract a one-for-one cutback in ANS deliveries.

In either case, the aggregate West Coast surplus may expand from the current 600 to 800 thousand barrels per day to as high as perhaps 1.2 million barrels per day by the end of the decade. Alaska's 90 mbpd auction is nevertheless significant over the short-term. It may not cause a collapse, but if it stimulates price discounting which in turn depresses the West Coast netback by, say, 50 cents a barrel, bidders would have to offer the State a 55-cent premium over the base price to offset overall losses in royalty and tax revenues.

APPENDIX: THE DISPLACEMENT EFFECT: State revenue gains or losses assuming maximum Displacement of producers' West Coast sales

BEFORE PRICE OF ALE CRUDE OIL				
	West Coast	Alaska	West Coast	
	Netback	Netback	Netback	
CIP price ^a	\$26.50	\$28.00		
TAPS tariff	(6.30)	(6.00)		
Tanker charge	(1.30)	(1.25)		
Prudhoe Bay netback price	\$19.00	\$10.75		

STATE-TOO DISPOSITION AND IN-VALUE PRICE				
(Thousands of barrels per day and dollars per barrel)				
	West Coast	Alaska	West Coast	
	Netback	Netback	Netback	
Physical deliveries ^b	500	720		1,620
ARCO MC refinery runs ^c	(100)	100		
Royalty oil contracts	(90)		90	
Total deliveries @ price below	502	1,020	90	1,620
Prudhoe Bay netback price	\$19.00	\$10.75		
WEIGHTED AVERAGE (in-value) PRICE			\$17.49	

Alaska Royalty Income				
Total deliveries @ price above	502	1,020	90	1,620
a Royalty rate	12.5%	12.5%	12.5%	
Gross royalty volume	63	128	12	203
In-kind adjustment ^d	(24)	(62)	0	
Net royalty volume	39	66	12	203
a Prudhoe Bay reference price	\$19.00	\$10.75	\$17.49	
STATE ROYALTY INCOME (\$1,000/day)	\$735	\$710	\$210	\$1,655

Severance-Tax Revenue				
Total deliveries @ price above	502	1,020	90	1,620
Exempt from severance tax	(10)	(70)	(10)	(203)
Subject to severance tax	492	950	80	1,410
a Prudhoe Bay reference price	\$19.00	\$10.75		
a Severance-tax rate	15.0%	15.0%	0.0%	
SEVERANCE TAX REVENUE (\$1,000/day)	\$1,332	\$1,028	\$0	\$2,360
TOTAL STATE REVENUE (\$1,000/day)	\$2,067	\$1,738	\$210	\$4,015
STATE REVENUE PER BARREL (Total production)				\$2.48

AFTER-SALE DISPOSITION AND IN-VALUE PRICE				
(Thousands of barrels per day and dollars per barrel)				
	West Coast	Alaska	West Coast	
	Netback	Netback	Netback	
Physical deliveries ^b	500	720		1,620
ARCO MC refinery runs ^c	(100)	100		
Old royalty-oil contracts	(90)		90	
New royalty-oil sale	(85)		85	
Total deliveries @ price below	417	1,020	183	1,620
a Prudhoe Bay netback price	\$19.00	\$10.75		
WEIGHTED AVERAGE (in-value) PRICE			\$17.40	
(Difference from status quo)			(0.09)	

Alaska Royalty Income				
Total deliveries @ price above	417	1,020	183	1,620
a Royalty rate	12.5%	12.5%	12.5%	
Gross royalty volume	52	128	23	203
In-kind adjustment ^d	(45)	(115)	160	
Net royalty volume	7	12	183	203
a Prudhoe Bay reference price	\$19.00	\$10.75	\$17.40	
STATE ROYALTY INCOME (\$1,000/day)	\$137	\$128	\$315	\$580
(Difference from status quo)			(0.02)	

Severance-Tax Revenue				
Total deliveries @ price above	417	1,020	183	1,620
Exempt from severance tax	(0)	(10)	(10)	(203)
Subject to severance tax	417	1,010	173	1,410
a Prudhoe Bay reference price	\$19.00	\$10.75	\$17.40	
a Severance-tax rate	15.0%	15.0%	0.0%	
SEVERANCE TAX REVENUE (\$1,000/day)	\$1,172	\$1,078	\$300	\$2,550
(Difference from status quo)			(0.01)	
TOTAL STATE REVENUE (\$1,000/day)	\$1,310	\$1,138	\$315	\$2,763
(Difference from status quo)			(0.03)	
STATE REVENUE PER BARREL (Total production)				\$1.70
(Difference from status quo)				(0.78)
REQUIRED PREMIUM ABOVE IN-VALUE PRICE ^e				\$0.51

Notes: a: Table 1.

b: Table 1.

c: Based on Arco's West Coast refinery capacity as reported in the Oil and Gas Journal Annual Refining Report, March 1983.

d: Reduction of in-value royalty volume resulting from State's in-kind taxing.

e: Margin by which the State's sale price must exceed the in-value price in order to offset the displacement effect.

Part 2

UNITIZATION ON THE NORTH SLOPE: CURRENT EVENTS

A. The Milne Point Unit

In October 1983, Conoco and co-lessees (Champlin, Cities Service, Union Oil Company, and Reading & Bates) asked the State for a reduction in the royalty rate attached to their oil and gas leases in the Milne Point Unit. (See the accompanying map.) This unusual request is no more unusual than the history of the Milne Point Unit itself. The companies' application, however, presents state leaders with a political dilemma.

The issue goes back to 1979, when Conoco (as field operator) filed a unitization plan just prior to the date set forth in the leases for termination of the leaseholders' exploration rights. Prompt approval of the unit plan, however, would have ensured extension of the leases beyond the initial 10-year term.

The Department of Natural Resources chose to condition unit approval on three points: (1) the lessees had to agree to an increase in the royalty from 12½ to 20 percent of production; (2) the costs of cleaning crude oil prior to shipment were

not to be assessed on the royalty volumes; and (3) the unit had to be developed and production initiated within three years.

The companies thus had the unpleasant choice of either agreeing to the State's demands or losing the leases altogether. They chose the former.

Now, five years later, the Conoco group is seeking a return to the initial royalty rate of 12½ percent. Conoco maintains that unless the 20-percent royalty rate is adjusted, the leaseholders stand to lose 4 cents a barrel on production beginning in 1986. This estimate is based on a projected wellhead value of \$19.95 for ANS oil, development costs of \$6.43 per barrel, and operating costs of \$5.47. At a 12½-percent royalty rate, the companies can look forward to a per-barrel profit of \$1.19.

Under Alaska law, the Commissioner of Natural Resources is authorized to grant a royalty reduction if she can show that "revenue produced from the field is insufficient to produce a reasonable rate of return with respect to a lessee's total investment." The statute, however, precludes the Commissioner from making such concessions until there has been two years of production from the field. (AS 38.05.180(j))

Oil production has not yet begun at Milne Point. But the Conoco group maintains that the Milne Point hydrocarbons represent an extension of the Kuparuk River field, which commenced production in 1981. Conoco argues that Kuparuk production experience is adequate to meet both the intent and the letter of the law.

The State disagrees. In an October 9 letter, the Department of Natural Resources denied Conoco's request for a royalty reduction. But the denial was not based on assessment of need. The De-

Petroleum Production Units
on the North Slope



partment simply found that Conoco's reserves were "discrete from the Kuparuk Field", and that profitability could not therefore be determined by reviewing Kuparuk development costs. Moreover, the Department believes that having concluded the fields are distinct, it is statutorily prohibited from granting a royalty reduction until Milne Point itself has two years of production experience.

The technical legal issue is no doubt a sticky one. More important, however, are the implications for other North Slope lease tracts. Since 1979, the state has affixed a royalty in excess of 12½ percent to some new leases. Such lease provisions, for example, apply to the Beaufort Sea and the Prudhoe Bay uplands, for example. Perhaps the holders of these leases will also view field development as marginal under these royalty terms, and especially now that real oil prices are clearly trending downward.

As an alternative to lease modifications, the legislature could choose to amend the formula for determining severance taxes. The economic limit factor (ELF) in the present law was intended to ensure that a company's severance tax obligation did not in itself contribute to premature abandonment of producing wells. From an economic point of view, a severance tax is equivalent to an ad-valorem royalty. The state could, at least in principle, obtain the desired sensitivity to costs with an appropriate ELF formula, without the need to make ad-hoc adjustments in royalty rates.

B. Endicott Unitization

The Alaska Division of Oil and Gas is working out the details for adding the Endicott Field northeast of Prudhoe Bay to the existing Duck Island Unit. This is the first occasion which a group of state

leases with diverse royalty and net-profits terms is to be unitized.

In 1981, we (Williams and Tussing) warned that agreement on unitization terms under these conditions could prove troublesome. Such a situation might also undermine the State's credibility as the final arbiter of differences between the working interest owners over allocation of shares in the reservoir. Worse yet, it could tempt the leaseholders to make side-deals or other collusive arrangements for the purpose of limiting their royalty or net profits liability to the State.

We are happy to report that negotiations between the state and the working interest owners are proceeding smoothly thus far. The parties have agreed, for example, to allocate production for purposes of royalty and net-profits calculations among the various tracts solely on the basis of geology. Then too, the unit provisions for under-and over-lifting will be administered in a way that leaves State revenues unaffected.

C. The Hemi Springs Unit

In January 1984, the Department of Natural Resources approved the Hemi Springs Unit Agreement, which had the effect of extending the term on 24 lease tracts. The situation was similar to the 1979 Milne Point unitization and the extension of those leases. This time, however, the State agreed to unitization and the associated lease extensions without extracting lessee concurrence in a royalty increase --- although it did extract other favorable terms including waiver of field costs for royalty volumes. In authorizing the unit, the State declared that lease expiration (absent unitization) or a forced royalty increase would hold up North Slope development.

Part 3

ALASKA'S LEASING PROGRAM

In August 1984, the U.S. Department of the Interior conducted a sale (No. 87) of oil and gas leases in the Beaufort Sea's Diapir Field. Under the agency's policy of area-wide leasing, this sale opened to petroleum exploration the Arctic outer continental shelf (OCS) from Point Barrow to the Canadian Border. In parallel, the State has enthusiastically pursued its own North Slope leasing program. Governor Sheffield told a June 1984 gathering in Juneau:

In terms of income to Alaska, there's simply nothing that can approach private industry finding and producing more oil and gas on State-owned land. In recognition of that, the State of Alaska is conducting a five year leasing program that will put about ten million acres out for bids between now and 1988. To put that into perspective, ten million acres, remember, equals a 50th of our statehood entitlement.

At the same time, the State has been easing environmental protection measures that have hindered arctic exploration and development. The seasonal drilling stipulations that permitted exploratory drilling only during periods of winter fast ice (about five months per year) have been shortened. Now drilling is restricted only for about two months in the autumn, coinciding with whale migrations. The Department of Natural Resources recently proposed that the Governor "allow limited use" of explosives for offshore seismic exploration, a practice banned by the Hammond Administration in 1975.

It is inappropriate, however, to attribute these changes wholly or mainly to a change in state policy or approach. They are more a function of the accumulation of experience with Arctic operations, and of improved understanding and respect between industry and DNR personnel.

A. The Exploration Incentive Credit

The State's vigorous North Slope oil-de-

velopment policy now also incorporates an "exploration incentive credit" in some lease sales. Companies may use this credit as an offset to royalty or severance tax obligations on any hydrocarbons production in Alaska. The credits are transferable: a company engaged in exploration within Alaska but without an existing production base may sell these credits to other companies that find them valuable. The credits are thus similar to sale and leasebacks of capital assets between taxpayers with different marginal tax rates.

Enabling legislation grants the Department of Natural Resources the discretion to select the terms of the exploration incentive credits and the lease sales to which they may apply. The Department, however, may not award a credit in excess of 50 percent of the actual costs of exploratory wells. DNR awards a percentage credit, capped by a dollar-per-foot cash limit.

Through 1984, the State had attached exploration incentive credits to the leases in three sales. The operators of four wells have thus far utilized this program to reduce their royalty and tax obligations to the State.

B. Net-Profits Bidding

The Alaska Legislature authorized the exploration credit in 1978 as part of its overhaul of State leasing practices. Those legislative changes also brought about the commencement of net-profits share leasing.

Under a net-profit share system, exploration and development costs attributable to a particular field are debited to an interest-bearing development account. Once production begins, oil and gas sales receipts are credited to that account. When the accumulated receipts finally offset the debited costs and accrued in-

terest, the State begins to share production revenues with the company according to the profit-sharing formula specified in the lease.

The State found a net-profits bidding system to be an attractive alternative to the traditional cash-bonus bidding system for several reasons. By sharing the risks of oil exploration, the state could hope to achieve higher returns under a net-profits system. Then too, because the state was in a cash-surplus situation in 1978, the early collection of revenues through bonus bidding was not essential to state operations. At the same time, petroleum companies were likely to offer the State a bigger cut of future revenues than they were capable of bidding in cash prior to the onset of production.

The net-profits system adopted by the State did not, however, infuse State risk-sharing into all aspects of petroleum exploration. Alaska refused, for example, to structure the system in a way that relieved the lessees of the risk of dry holes. Only those costs directly associated with producing wells were eligible for inclusion in the cost-debit account. The State, nevertheless, offered net-profits lessees a partial offset to the risk of dry holes through its program of explora-

tion incentive credits.

Although Alaska has used net-profits as a bid variable only once (in the December 1979 joint federal-state Beaufort Sea sale), net-profits leasing is nevertheless an integral part of its leasing strategy. The state has largely returned to a bonus-bid system, but the bidding is in addition to a fixed net-profit share and a fixed royalty.

C. Negative Bonus Payments

Onto this system of combined cash bonuses, royalties, and net-profit shares, the State has attached its exploration incentive credit. This arrangement has resulted in an overall leasing program that is a curious blend of risk-minimizing and risk-sharing elements. Moreover, it is responsible for the phenomenon of negative bonuses on nonproductive tracts.

Negative bonuses are only now beginning to appear, and in a form that is not wholly tangible. For example, Exxon and Sohio paid the State a \$4.2 million bonus in 1983 for a lease tract in the Beaufort Sea. The next year, the operator applied and received a \$12.4 million exploration credit for costs incurred in drilling in that tract. The net loss of \$8.2 million could thus be characterized as a negative bonus bid.

PACIFIC OIL INSIGHTS: Issues in Print

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| No. 1 | ARCO and its Critics
The North Slope Crude-Oil Transfer-Price Controversy |
| No. 2 | Toward an Understanding of West Coast Residual-Oil Supply and Demand |
| No. 3 | World Oil Markets: Part I
ARTA's 1984 World Oil Outlook |
| No. 4 | World Oil Markets: Part II
The Long-Run View |
| No. 5 | Disposition of Alaska State Royalty Oil |

Rep Szymanski



Official Business

Alaska State Legislature

HOUSE SPECIAL COMMITTEE ON OIL AND GAS

Pouch V
State Capitol
Juneau, Alaska 99811

MEMORANDUM

To: House Special Committee on Oil and Gas
From: Rep. Mike Davis, Chairman
Date: January 25, 1985
Re: Materials packet for Jan. 25 meeting

Attached are the materials that will be referenced during this afternoon's meeting. The meeting will be held at 3:30 pm in House Finance.

A handwritten signature, likely of Rep. Mike Davis, written in dark ink.

STATE OF ALABAMA
COMPETITIVE ROYALTY OIL SALE

PAGE 1

DEC. 11, 1984

PURCHASER	LOT #	ESTIMATED BARRELS PER DAY	CONTRACT LENGTH (IN DAYS)	TOTAL EST. BARRELS PER CONTRACT	BASE PRICE	PREMIUM	TOTAL REALIZED (1)	DIFFERENCE REALIZED (1) (2)
CATEGORY A: KUPARUK								
CHEVRON	* 1	5,000	182.5	912,500	016.92	00.02	016,187,750.00	0884,177.13
UNION	* 2	5,000	182.5	912,500	016.92	00.53	015,923,125.00	0539,352.13
CHEVRON	* 3	5,000	182.5	912,500	016.92	00.17	015,594,625.00	0211,052.13
SUBTOTAL		15,000		2,737,500			047,705,500.00	01,554,781.38
HIGHEST PREMIUM BID:			00.02	AVERAGE PREMIUM BID:		00.51		
CATEGORY B: PRUDHOE								
U.S. OIL	1	5,000	365	1,825,000	017.92	01.04	034,682,000.00	01,783,635.75
U.S. OIL	2	5,000	365	1,825,000	017.92	01.04	034,682,000.00	01,783,635.75
CHEVRON	* 3	5,000	365	1,825,000	017.92	01.03	034,583,750.00	01,685,485.75
CHEVRON	* 4	5,000	365	1,825,000	017.92	01.03	034,583,750.00	01,685,485.75
CHEVRON	* 5	5,000	365	1,825,000	017.92	01.03	034,583,750.00	01,685,485.75
TEXACO	* 6	5,000	365	1,825,000	017.92	00.64	033,872,000.00	0973,635.75
TEXACO	* 7	5,000	365	1,825,000	017.92	00.64	033,872,000.00	0973,635.75
TEXACO	* 8	5,000	365	1,825,000	017.92	00.64	033,872,000.00	0973,635.75
TEXACO	* 9	5,000	365	1,825,000	017.92	00.64	033,872,000.00	0973,635.75
TEXACO	* 10	5,000	365	1,825,000	017.92	00.64	033,872,000.00	0973,635.75
SUBTOTAL		50,000		18,250,000			0342,315,250.00	013,331,887.50
HIGHEST PREMIUM BID:			01.04	AVERAGE PREMIUM BID:		00.64		
CATEGORY C: PRUDHOE								
CHEVRON	* 1	5,000	182.5	912,500	017.92	01.03	017,291,675.00	0842,782.00
TEXACO	* 2	5,000	182.5	912,500	017.92	00.64	016,936,000.00	0486,827.00
TEXACO	* 3	5,000	182.5	912,500	017.92	00.64	016,936,000.00	0486,827.00
TEXACO	* 4	5,000	182.5	912,500	017.92	00.64	016,936,000.00	0486,827.00
SONIO	5	5,000	182.5	912,500	017.92	00.51	016,817,375.00	0368,282.00
SUBTOTAL		25,000		4,562,500			084,917,250.00	02,671,389.38
HIGHEST PREMIUM BID:			01.03	AVERAGE PREMIUM BID:		00.69		
TOTALS FOR ALL LOTS:		18	90,000	25,550,000			0474,938,000.00	017,557,978.25

(1) THESE PROJECTIONS ASSUME THAT CURRENT MARKET CONDITIONS AND PRICES CONTINUE.

(2) THIS AMOUNT IS THE DIFFERENCE BETWEEN THE ESTIMATED ROYALTY-IN-VALUE RECEIPTS BASED ON THE VOLUME WEIGHTED AVERAGE OF PRODUCERS' REPORTED NETBACK PRICES (OCTOBER) AND THE ESTIMATED RECEIPTS OF THE COMPETITIVE SALE BASED ON THE BID PREMIUM PLUS THE BASE PRICE.

(*) PRIORITY BIDDERS

STATE OF ALABAMA
COMPETITIVE ROYALTY OIL SALE

DEC. 11, 1984

NUMBER OF BIDS SUBMITTED:	49
NUMBER OF BIDDERS PARTICIPATING:	8
HIGHEST PREMIUM BID:	1.04
SUBMITTED BY: U.S. OIL	
ESTIMATED TOTAL REVENUES FROM SALE:	\$474,938,000
COMPANY WITH MOST WINNING BIDS:	TEXACO WITH 8 LOTS
NUMBER OF LOTS WON BY PRIORITY BIDDERS:	15
NUMBER OF LOTS WON BY NON-PRIORITY BIDDERS:	3

JUL 14, 1985

STATE OF ALASKA
DEPARTMENT OF NATURAL RESOURCES
DIVISION OF OIL AND GAS

ESTIMATED PRODUCTION FOR PRUDHOE BAY AND KUPARUK RIVER UNITS

YEAR	ESTIMATED TOTAL PRODUCTION (BARRELS PER DAY)			ESTIMATED ROYALTY (BARRELS PER DAY)			ESTIMATED SALES OF ROYALTY OIL (BARRELS PER DAY)							
	TOTAL PRUDHOE	(1) TOTAL KUPARUK	TOTAL	PRUDHOE ROYALTY	KUPARUK ROYALTY	TOTAL ROYALTY	NAPCO	(2) BVEA (OLD)	(3) BVEA (PROPOSED)	(4) TESORO (OLD)	(5) TESORO (NEW)	(6) CHEVRON	(7) COMPETITIVE SALE	ROYAL IN VAL
1984	1,500,000	120,000	1,620,000	187,500	15,000	202,500	35,000	5,000		39,765		18,000		184.7
1985	1,500,000	100,000	1,600,000	187,500	22,500	210,000	35,000		5,000	45,999	25,001	18,000	65,000	15.0
1986	1,500,000	100,000	1,600,000	187,500	22,500	210,000	35,000		5,000	45,999	25,001	18,000		88.0
1987	1,475,000	100,000	1,575,000	184,375	22,500	206,875	35,000		4,917	45,233	25,567	17,700		78.4
1988	1,325,000	200,000	1,525,000	165,625	25,000	190,625	35,000		4,417	40,633	22,967	15,900		71.7
1989	1,175,000	200,000	1,375,000	146,875	25,000	171,875	35,000		3,917	36,833	20,367	14,100		62.4
1990	1,050,000	200,000	1,250,000	131,250	25,000	156,250	35,000		3,500	32,200	18,200	12,600		54.7
1991	950,000	200,000	1,150,000	118,750	25,000	143,750	35,000		3,167	29,133	16,467	11,400		48.5
1992	850,000	200,000	1,050,000	106,250	25,000	131,250	35,000		2,833	26,066	14,734	10,200		42.4
1993	750,000	200,000	950,000	93,750	25,000	118,750	35,000		2,500	23,000	13,000	9,000		36.2
1994	650,000	170,000	820,000	81,250	21,250	102,500	35,000		2,167	19,933	11,267	7,000		30.3
1995	575,000	145,000	720,000	71,875	18,125	90,000	35,000							25.1
1996	510,000	120,000	630,000	63,750	15,000	78,750	35,000							21.7
1997	460,000	100,000	560,000	57,500	12,500	70,000	35,000							18.6
1998	420,000	80,000	500,000	52,500	10,000	62,500	35,000							16.1
1999	380,000	75,000	455,000	47,500	9,375	56,875	35,000							14.0
2000	340,000	65,000	405,000	42,500	8,125	50,625	35,000							12.2
2001	300,000	55,000	355,000	37,500	6,875	44,375	35,000							10.6
2002	270,000	50,000	320,000	33,750	6,250	40,000	35,000							9.3
2003	240,000	40,000	280,000	30,000	5,000	35,000	35,000							8.1
2004	210,000	35,000	245,000	26,250	4,375	30,625								7.1
2005	180,000	25,000	205,000	22,500	3,125	25,625								6.2
2006	160,000	25,000	185,000	20,000	3,125	23,125								5.4
2007	140,000	20,000	160,000	17,500	2,500	20,000								4.7
2008	110,000	20,000	130,000	13,750	2,500	16,250								4.0
2009	80,000	10,000	90,000	10,000	1,250	11,250								3.4
2010	50,000	10,000	60,000	6,250	1,250	7,500								2.9

NOTES: (1) DNR ESTIMATE OF FIELD PERFORMANCE, OCTOBER 1984.

(2) BVEA'S CURRENT CONTRACT EXPIRES JUNE 30, 1985.

(3) BVEA'S PROPOSED TEN-YEAR CONTRACT WOULD COMMENCE FOUR MONTHS AFTER APPROVAL BY THE LEGISLATURE AND GOVERNOR. QUANTITY IS 2.667% OF DAILY PRUDHOE ROYALTY OIL.

(4) TESORO'S CURRENT CONTRACT CALLS FOR A MAXIMUM QUANTITY OF 24.533% OF DAILY PRUDHOE ROYALTY OIL LESS COOK INLET ROYALTY PRODUCTION. THE QUANTITY IS 21.208% IN 1984, AND WILL BE 21.326% STARTING JAN. 1, 1995. THIS CONTRACT WILL BE INCREASED TO ITS MAXIMUM QUANTITY ON OCTOBER 1, 1985 DUE TO CANCELLATION OF THE COOK INLET CONTRACT ON THAT DATE. THE CONTRACT EXPIRES JANUARY 1995.

(5) MOST OF THIS VOLUME (ABOUT 25,000 BPD), WHICH IS CURRENTLY BEING TAKEN "IN VALUE," WAS SOLD COMPETITIVELY FOR DELIVERY APRIL 1, 1985 THRU SEPT. 30, 1985. ON OCTOBER 1, 1985 IT IS ANTICIPATED THAT TESORO WILL COMMENCE DELIVERIES UNDER ITS 12/9/83 PRUDHOE CONTRACT, WHICH HAS A MAXIMUM QUANTITY OF 13.86% OF DAILY PRUDHOE ROYALTY OIL AND EXPIRES JAN. 1, 1995.

(6) CHEVRON'S CONTRACT CALLS FOR A MAXIMUM QUANTITY OF 9.6% OF DAILY PRUDHOE ROYALTY OIL. THE CONTRACT EXPIRES JANUARY 1, 1995.

(7) DELIVERIES WILL COMMENCE APRIL 1, 1985 FOR 50,000 BPD OF PRUDHOE BAY UNIT ROYALTY OIL AND 15,000 BPD OF KUPARUK RIVER UNIT ROYALTY OIL, AND WILL CONTINUE FOR ONE-YEAR, AND SIX-MONTH PERIODS, RESPECTIVELY, AS A RESULT OF THE DEC. 11, 1984 COMPETITIVE SALE. PRIOR TO THAT TIME THIS OIL REMAINS "IN VALUE."

STATE OF ALABAMA
AND IN-KIND ROYALTY OIL CONTRACTS
(in barrels per day)

NOMINATION PERCENTAGES EFFECTIVE APRIL 1, 1985

PRUDHOE BAY UNIT

COMPANY	% OF DAILY ROYALTY OIL	QUANTITY	TERM	PRICE	
NAPCO	0.186667	35,000.06	11/26/79 - 12/31/2003	EXHIBIT B	1/
TESORO	0.213260	39,906.25	01/01/83 - 01/01/95	IN-VALUE	2/
CHEVRON	0.096000	18,000.00	05/30/84 - 01/01/95	IN-VALUE + \$.30	3/
BVER 4/	0.026667	5,000.06	07/01/84 - 06/30/84	IN-VALUE + \$.30	3/
CHEVRON (COMP SALE)	0.026667	5,000.00	04/01/85 - 09/30/85	18.95	6/
CHEVRON (COMP SALE)	0.080000	15,000.00	04/01/85 - 03/31/86	18.95	6/
TEXACO (COMP SALE)	0.080000	15,000.00	04/01/85 - 09/30/85	18.56	6/
TEXACO (COMP SALE)	0.133333	25,000.00	04/01/85 - 03/31/86	18.56	6/
SOHIO (COMP SALE)	0.026667	5,000.00	04/01/85 - 09/30/85	18.43	6/
U.S. OIL (COMP SALE)	0.053333	10,000.00	04/01/85 - 03/31/86	18.96	6/
TOTAL RIK	0.922594	172,906.38			
TOTAL RIV	0.077406	14,513.62		IN-VALUE	2/
TOTAL RIK & RIV	1.000000	187,500.00			

NOMINATION PERCENTAGES EFFECTIVE OCTOBER 1, 1985

PRUDHOE BAY UNIT

COMPANY	% OF DAILY ROYALTY OIL	QUANTITY	TERM	PRICE	
NAPCO	0.186667	35,000.06	11/26/79 - 12/31/2003	EXHIBIT B	1/
TESORO PB #1	0.245330	45,999.38	01/01/83 - 01/01/95	IN-VALUE	2/
TESORO PB #2	0.138670	26,000.63	10/01/85 - 01/01/95	IN-VALUE + \$.35	5/
CHEVRON	0.096000	18,000.00	05/30/84 - 01/01/95	IN-VALUE + \$.30	3/
CHEVRON (COMP SALE)	0.080000	15,000.00	04/01/85 - 03/31/86	18.95	6/
TEXACO (COMP SALE)	0.133333	25,000.00	04/01/85 - 03/31/86	18.56	6/
U.S. OIL (COMP SALE)	0.053333	10,000.00	04/01/85 - 03/31/86	18.96	6/
TOTAL RIK	0.933334	175,000.06			
TOTAL RIV	0.066666	12,499.94		IN-VALUE	2/
TOTAL RIK & RIV	1.000000	187,500.00			

- 1/ Current EXHIBIT B price as of Oct 84 production month is \$18.28773.
- 2/ In-value price (10/84) = Weighted average price less field cost of \$.69 per barrel. Current in-value price as of Oct 84 is \$17.3365.
- 3/ In-value price (10/84) + \$.30 premium + \$.69 field cost.
- 4/ This contract will terminate 06/30/85. A long-term contract to BVER for 5,000 bpd will be submitted to the Legislature this Session and commence four months after approval by the Governor and the Legislature.
- 5/ In-value price (10/84) + \$.35 premium + \$.69 field cost.
- 6/ This price will fluctuate monthly based on posted prices of West Texas Sour crude.

STATE OF ALABAMA
AND IN-KIND ROYALTY OIL CONTRACTS
(in barrels per day)

NOMINATION PERCENTAGES EFFECTIVE APRIL 1, 1985

KUPARUK RIVER UNIT

COMPANY	% OF DAILY ROYALTY OIL	QUANTITY	TERM	PRICE	
CHEVRON (COMP SALE)	0.222222	5,000.00	04/01/85 - 09/30/85	17.09	1/
CHEVRON (COMP SALE)	0.222222	5,000.00	04/01/85 - 09/30/85	17.09	1/
UNION (COMP SALE)	0.222222	5,000.00	04/01/85 - 09/30/85	17.45	1/
TOTAL RIK	0.666667	15,000.00			
TOTAL RIV	0.333333	7,500.00		IN-VALUE	2/
TOTAL RIK & RIV	1.000000	22,500.00			

NOMINATION PERCENTAGES EFFECTIVE OCTOBER 1, 1985

KUPARUK RIVER UNIT

COMPANY	% OF DAILY ROYALTY OIL	QUANTITY	PRICE	
CHEVRON (COMP SALE)	0.000000	0.00		
CHEVRON (COMP SALE)	0.000000	0.00		
UNION (COMP SALE)	0.000000	0.00		
TOTAL RIK	0.000000	0.00		
TOTAL RIV	1.000000	22,500.00	IN-VALUE	2/
TOTAL RIK & RIV	1.000000	22,500.00		

1/ This price will fluctuate monthly based on posted prices of West Texas Sour crude.

2/ In-value price (10/84) = weighted average price less field cost.
of \$.40 per barrel. Current in-value price as of Oct 84 is \$16.4587,

STATE OF ALASKA
COOK INLET IN-KIND ROYALTY OIL CONTRACTS
(in barrels per day)

NOMINATION PERCENTAGES EFFECTIVE APRIL 1, 1985

COMPANY	% OF DAILY ROYALTY OIL	QUANTITY	TERM	PRICE	
TESORO	100.000000	6,718.75	01/01/84 - 09/30/85	IN-VALUE	1/
TOTAL RIK	100.000000	6,718.75			
TOTAL RIV	0.000000	0.00			
TOTAL RIK & RIV	100.000000	6,718.75			

NOMINATION PERCENTAGES EFFECTIVE OCTOBER 1, 1985

COMPANY	% OF DAILY ROYALTY OIL	QUANTITY	PRICE	
TESORO	0.000000	0.00		
TOTAL RIK	0.000000	0.00		
TOTAL RIV	100.000000	6,718.75	IN-VALUE	1/
TOTAL RIK & RIV	100.000000	6,718.75		

1/ In-value price (10/84) = weighted average price less transportation cost. Current in-value price as of Oct 84 is \$24.854.

State of Alaska
Department of Natural Resources
Final Findings & Determination
to Sell Prudhoe Bay Royalty Oil to
Golden Valley Electric Association, Inc.
January 16, 1985

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I. Introduction	1
II. Background and Chronology	1
III. Summary of Proposed Contract Terms	2
IV. Comments Received	3
V. Contract Revisions	4
VI. Findings and Determinations	7
VII. Conclusion	9

I. Introduction.

The State of Alaska proposes to sell 2.667% of its daily royalty oil (approximately 5,000 barrels per day) from the Prudhoe Bay Unit to Golden Valley Electric Association, Inc. (GVEA) under a long-term, noncompetitive contract. In accordance with AS 38, the Department of Natural Resources must determine whether this disposal serves the state's best interest before the sale may take place. This final finding describes the proposed sale and analyzes its potential effects.

II. Background and Chronology.

GVEA is the public cooperative electric utility in Fairbanks. The state's previous long-term royalty oil contract with GVEA, executed in 1976, was the first royalty oil contract negotiated and executed after the 1976 establishment of the Alaska Royalty Oil and Gas Development Advisory Board. GVEA requested royalty oil so that crude oil might be used as turbine fuel for power generation in the event that the cost of turbine fuel from the North Pole Refinery became prohibitive.

GVEA's contract with the state was for the purchase of 5,000 bpd. GVEA did not exercise its option to purchase royalty oil until June 17, 1981. GVEA assigned its contract rights to North Pole Refinery, Inc., which is now owned by MAPCO Petroleum Inc. (MAPCO), in exchange for a price discount on the turbine fuel refined from the royalty oil. MAPCO refines the royalty oil into jet fuels, diesel, heating oil, and other refined products in addition to turbine fuel, and reinjects the remaining return oil into the Trans Alaska Pipeline System (TAPS).

In a November 1982 letter to the Department of Natural Resources, GVEA requested an extension of its contract for an additional ten years. No action was taken on that request pending the change of administrations. In March 1983, the new administration began negotiations with GVEA on a new ten-year contract to assist in satisfying the needs of GVEA's 50,000 in-state consumers. Notice of the proposed long-term sale to GVEA was published on November 8, 1983. A notice of that royalty board meeting, which included a review of the proposed GVEA disposal (among other things), was also published on November 16, 1983.

The Alaska Royalty Oil and Gas Development Advisory Board's December 7, 1983 review of the proposed GVEA disposal and the agreement, as negotiated to that date, revealed specific concerns by both the public and board members with respect to the state's option on return oil and the relationship between MAPCO and GVEA. In view of those reservations and the limited time for further negotiation, the long-term GVEA contract was not presented for legislative approval. Instead, an interim one-year contract not requiring legislative approval was put into effect. Subsequently, GVEA and the Department undertook sporadic negotiations during early 1984 with the goal of making long-term contract revisions responsive to the issues raised at the December 7, 1983 royalty board meeting. During this period, the assignment agreement between MAPCO and GVEA also remained in effect. On September 12, 1984, the Director of the Division of Oil & Gas briefed the royalty board on the Department's continuing negotiations with GVEA and MAPCO.

On November 29, 1984, GVEA, MAPCO and the Department reached tentative agreement on a new long-term contract to be presented to the royalty board and the legislature. The terms of the proposed contract, which were included in the Department's Preliminary Findings and Determination to Sell Prudhoe Bay Royalty Oil to Golden Valley Electric Association, Inc. of December 7, 1984, are again summarized below.

III. Summary of Proposed Contract Terms.

1. Price: The total price per barrel to be received by the state in the proposed contract is the sum of the following components:
 - (a) The (monthly) volume weighted average of the Prudhoe Bay lessees' current reported netback prices, as adjusted for transportation and other costs by those lessees.
 - (b) Additional amounts, primarily from GVEA's assignee (MAPCO), if the state obtains a favorable resolution of litigation disputing the validity of the Prudhoe Bay lessees' current reported netback prices (State of Alaska, et al vs. Amerada Hess, et al).
 - (c) Those cleaning and dehydration field costs which the state must pay when either taking its royalty share in-value (receiving money from the Prudhoe Bay lessees equal to the volume weighted average of their current reported netback prices, as may be retroactively adjusted upon resolution of the Amerada Hess litigation) or taking title to its royalty share of oil for an "in-kind" disposal. In a 1980 partial settlement of the Amerada Hess litigation, the state acknowledged limited responsibility for certain field costs in either case. And,
 - (d) A \$.30 per barrel premium.
2. Term:
 - (a) The date of first delivery will be four months after enactment of legislation by the State of Alaska (including approval by the Governor) approving the agreement unless the state, in its sole discretion, sets an earlier date.
 - (b) The termination date of the contract is June 30, 1995.
 - (c) The price specified above is subject to renegotiation in July 1987 and every two years thereafter for the duration of the contract.
3. Quantity: 2.667% (approximately 5,000 bpd) of daily royalty oil from the Prudhoe Bay Unit.
4. Point of Delivery: Custody transfer meters into the Trans Alaska Pipeline system at Prudhoe Bay.

5. In-State Use: When the Department executes the agreement, it will also execute an agreement with GVEA and MAPCO approving GVEA's assignment of its royalty oil to MAPCO. The state retains the right to terminate its approval of the MAPCO/GVEA relationship, in which MAPCO provides GVEA a specific discount on a specific quantity of turbine fuel. Should the assignment be terminated, GVEA's continued receipt of royalty oil would be conditioned upon GVEA arranging a new means of using royalty oil to provide GVEA consumers electricity at a cost lower than otherwise possible.
6. Security: GVEA will arrange to provide a letter of credit to the state in the amount of \$5,316,000, which is equivalent to approximately sixty days' worth of oil. Upon default, this letter is redeemable upon signature of the Attorney General and the Commissioner.
7. Return Oil: Throughout the term of the contract, the state will have the option to purchase all return oil produced, refined, or exchanged under the contract. In consideration of MAPCO's consent to accept the majority of any liabilities stemming from the resolution of the Amerada Hess dispute, the state has agreed not to exercise its return oil option so long as MAPCO receives royalty oil under the GVEA royalty oil contract.
8. Standard Contract Terms: The contract will contain all appropriate standard state contract terms.

IV. Comments Received

Written comments addressing the Preliminary Finding and Decision were received from two parties prior to the close of the comment period. By a letter dated December 28, 1984, Tesoro Alaska Petroleum Company (Tesoro) expressed concern about the extent to which the proposed disposal may benefit MAPCO. Tesoro suggested that a more favorable contract for GVEA might have been secured during negotiations with MAPCO. The Department agrees that the benefits to GVEA of the proposed disposal are modest. While perhaps not sufficiently emphasized in the Preliminary Findings, the proposed disposal is based upon benefits to the state as well as to GVEA. Consequently, the price terms of the proposed disposal are similar to those of the state's recently executed royalty oil contracts with Tesoro and Chevron.

Since the state would be a major financial beneficiary of the proposed disposal, more advantageous contract terms for GVEA could not necessarily be borne by MAPCO. Although MAPCO must benefit to some degree as an indirect party to the agreement, the Department has sought to confine (to the extent possible in collective bargaining) the benefits of the proposed disposal to the state and GVEA. Upon receiving Tesoro's comments, the Department encouraged direct consultations between Tesoro and GVEA. As these discussions did not lead GVEA to conduct further negotiations with MAPCO, GVEA has presumably secured the best terms possible from MAPCO as well as the state.

By a letter dated January 8, 1985, James B. Gottstein, the Chair of the Royalty Oil and Gas Advisory Board (Royalty Board), also submitted comments related to the proposed disposal. Gottstein was concerned with a possible relationship between this disposal and the decision to shorten the contract terms of three 5,000 b/d lots of Kuparuk River royalty oil from one year to six months for the competitive royalty oil sale of December 11, 1984. However, the Kuparuk oil withdrawn from the sale was not committed to MAPCO or GVEA as Gottstein apparently believed was the case. That oil remains uncommitted.

Gottstein also said the Department did not properly inform the Royalty Board of that decision, as he believed was required. The Royalty Board review mandated by AS 38.06.050 extends only to royalty oil dispositions for which legislative approval is required. The December 11, 1984 competitive royalty oil sale was a short-term market conditions sale, for which legislative approval was not required (AS 38.06.055(b)(1)). At the September 12, 1984 Royalty Board meeting, the division did brief the Royalty Board about the competitive sale. In the Invitation to Bid discussed at the Royalty Board meeting, future revisions to sale terms at the direction of the commissioner were clearly contemplated. The rationale for the Department's revision was also publicly analyzed in-depth in the November 28, 1984 Supplemental Findings for the Competitive Royalty Oil Sale. Royalty Board input was not required for the decision to decrease the terms of the Kuparuk lots, and the division's consultation with regard to the sale in general exceeded statutory and regulatory requirements.

V. Contract Revisions

Since publication of the previous preliminary notice in November, 1983, the proposed GVEA contract has been altered by the Department and GVEA to address the concerns raised about the earlier proposed contract. Two key issues, both of which led to revisions in the contract form, were in-state use and return oil.

Currently, the consumer benefits of the GVEA contract depend on MAPCO's agreement with GVEA to provide turbine fuel at a price lower than what GVEA would otherwise pay. Under GVEA's present contract, the state is unable to enforce the degree of advantage afforded to GVEA since that agreement is between GVEA and MAPCO only. Consequently, Section 2.11 (In-State Use) of the proposed contract has been rewritten, and an agreement between the state, GVEA, and MAPCO has been added to assure that the agreed upon refining arrangement with MAPCO will be maintained, within certain bounds, over the life of the GVEA contract. The state will have the option to terminate its approval of the assignment should the relationship between GVEA and MAPCO change materially.

The state has insisted on the option to terminate the contract on these grounds since the proposed disposal is based in part on the specific benefits provided for GVEA members. Approximately one-third (625 barrels) of GVEA's daily turbine fuel requirements would be provided at a discounted price to GVEA through the proposed disposal. When compared to the refining charge which GVEA must pay for the remaining two-thirds of its turbine fuel needs, this discount translates into an annual savings to GVEA of about \$550,000.

GVEA's total turbine fuel consumption now accounts for about 45% of its fuel use. The balance of GVEA's power generation comes from coal. Given the operations costs of GVEA's turbine fuel and coal-fired generation and the volume of discounted turbine fuel the proposed royalty oil contract would provide GVEA, MAPCO's discount to GVEA would reduce the GVEA consumer's average power generation cost by about 1.57%. Due to a mathematical oversight, the Preliminary Findings erroneously implied that an average power generation cost savings to GVEA of about 1% would result from the proposed disposal.

The state's ability to ensure that the GVEA contract would continue to provide these consumer benefits has been reinforced by the addition of Exhibit A, an agreement (attached to the proposed GVEA contract) between the State, GVEA, and MAPCO. Article II of Exhibit A calls for MAPCO and GVEA to keep the state apprised of any changes in their assignment agreement, and reiterates that changes to that agreement which materially affect the consumer benefits are grounds for termination of the assignment approval by the state. In addition, Article III of Exhibit A ensures that MAPCO will give nine (9) months written notice to GVEA before reducing the amount of royalty oil taken, since GVEA must also notify the state nine (9) months in advance of such a reduction.

Residual oil is a by-product of most refineries, including the North Pole Refinery. Residual oil represents that portion of a barrel of crude oil which a refinery is unable to process into product. Because MAPCO is situated to reinject residual oil into TAPS (where it re-emerges as whole oil at Valdez), this oil is also referred to as "return oil".

The assignment agreement between MAPCO and GVEA allows MAPCO to keep and dispose of the royalty return oil for export. Because MAPCO appeared to be a major beneficiary of the prior GVEA royalty oil contract, in part through its control over the return oil, the state has sought additional consideration from MAPCO for state approval of the assignment agreement. Consequently, Article IV of Exhibit A makes MAPCO primarily responsible for any GVEA liabilities resulting from retroactive price adjustments attending the resolution of the Amerada Hess dispute.

GVEA would be responsible only for one-eighth of the Amerada Hess liability accrued in a period not to exceed one year. The remaining seven-eighths of the liability accrued in that period, and all liabilities accrued in all other years during the term of the proposed GVEA contract, would be borne by MAPCO. This provision of Exhibit A insulates GVEA from the effects of a favorable outcome for the state in the Amerada Hess dispute and consequently, increases the benefits received by GVEA's consumers. MAPCO's agreement to bear the largest share of any future liability would increase the effective benefit to GVEA members of the proposed royalty oil contract by several fold. With this protection, GVEA largely avoids a potential liability which could accumulate for a period of up to ten years and consequently harm its financial position.

The return oil provision of the proposed contract gives the state the option to purchase all return oil produced, refined, or exchanged under the contract. However, in consideration of Article IV of Exhibit A, by which MAPCO accepts the potential Amerada Hess liabilities discussed above, the state agrees not to exercise its right to purchase return oil so long as MAPCO receives royalty oil under the GVEA royalty oil contract.

In addition to the revisions of the in-state use and return oil provisions, other changes have been made to the proposed 1983 contract to conform GVEA's proposed contract to the state's most recent contract forms where possible. These changes can be found in Section 7.1 (Default), Section 8.2 (Inability to Receive Oil) Article XIX (Amendment), and a number of minor areas.

For the state's protection, a new clause in Section 8.2 assigns to the state all transportation rights, including nominations, charter agreements, and any other transportation arrangements which GVEA has for state royalty oil, in the event of the purchaser's inability to receive royalty oil. This is now a standard provision for state royalty oil contracts and is found in both the backup and primary form contracts for the December 11, 1984 competitive sale.

An additional sentence in Article XIX (Amendment) states that, "Any material amendment to the contract which appreciably reduces the consideration received by the state requires prior approval of the Legislature of the State of Alaska". This contract language is required by AS 38.05.183(f).

In Section 7.1 (Default), the first of the six conditions of default listed has been added so that the state may, with evidence of impending failure to perform, declare a condition of default. This is an important protection for the state since there is often circumstantial evidence, such as inadequate transportation arrangements, which precede actual failure to perform.

Minor revisions can be found in two sections of Article V (Payments and Accounting). These revisions, which track the state's recent royalty oil contracts, make the terms of payment somewhat more stringent for the purchaser. Section 5.3 now calls for payment by wire transfer, and no longer provides for clerical mistakes as an acceptable basis for failing to pay the amount billed. Section 5.7 also eliminates several circumstances previously specified as acceptable grounds for failure to make full payment.

The remaining changes to the GVEA contract are technical in nature and concern numerical corrections, date corrections, definition clarifications, changes in the format, and minor revisions to Sections 3.2 (Good Standing and Due Authorization) and 16.1 (Preferential Hiring). Also, the word "Royalty" has been deleted throughout the contract wherever it precedes the word "Oil" and certain terms made unnecessary by the introduction of the term "Purchase Price" have been deleted.

The clauses particular to GVEA's situation, and to long-term negotiated contracts in general, have been left intact. Examples include Section 2.1 (Quantity), where GVEA may elect to change, within certain bounds, the quantity of royalty oil received, and Section 7.3 (Seller's Remedies), which allows the state to release GVEA from the in-state use requirement, at the state's sole discretion. Section 8.1 (Disposition of Oil Upon Default or Termination) also falls into this category, but GVEA's obligation to continue payment in event of default has a four-month, rather than the standard seven-month, duration. This is because the Prudhoe Bay Unit producers will, by contractual agreement, accept physical custody of small quantities of royalty oil with only a 90-day notice. The volume of royalty oil proposed for sale to GVEA falls within that quantity range.

VI. Findings and Determinations.

1. Competitive bidding is waived.

I have determined in accordance with AS 38.05.183(a) that the best interest of the state does not require competitive bidding for this disposal. The best interest of the state is served by making this award on factors other than the highest price received from a competitive sale. Those factors are detailed in the following section of this document.

In order to realize the objectives implied by the considerations listed in AS 38.05.182-183 and AS 38.06.070 and to obtain benefits for Alaska consumers, disposal by competitive bid with the award determined entirely upon the cash value offered is not in the best interest of the state in this instance. Rather, it is in the best interest of the state to dispose of this royalty oil to GVEA, which offers maximum benefits to state citizens and which will pay a \$.30 premium over what the state would have received had the state taken the oil at the weighted average of the Prudhoe Bay lessees' current reported netback prices, as may be retroactively adjusted by resolution of the Amerada Hess litigation.

2. The sale is in the best interests of the State.

Under AS 38.05.183(e) a noncompetitive sale, exchange, or other disposal of royalty oil or gas taken in-kind by the state may be awarded by the commissioner to the prospective buyer whose proposal offers maximum benefits to the citizens of the state.

In accordance with AS 38.05.035(e), AS 38.05.183(c) and (e), and 11 AAC 03.010(d), I find and determine that the taking of royalty oil in-kind and the disposal of that oil to Golden Valley Electric Association, Inc. (GVEA) for use in-state is in the best interests of the state. The following has been considered in making this determination:

a. The state will receive no less from this sale than if it had continued to take its royalty oil in-value at the weighted average of the Prudhoe Bay lessees' current reported netback prices as retroactively adjusted by litigation. The premium of \$.30 over that price will likely offset any adverse effects on that price (and state revenues) which could occur when the state meets the needs of a refinery (in this case MAPCO) that would otherwise be a crude oil customer on the West Coast. The Commissioner's Preliminary Findings and Determination to Negotiate Backup Royalty Oil Contract(s) and Conduct a Competitive Royalty Oil Sale of July 12, 1984 detail those potential effects. It is not possible to forecast the impact of customer displacement on West Coast prices, let alone its influence on the current reported in-value price. However, the amount of the premium is likely to cover a reasonable differential. Further, MAPCO presently receives similar amounts of crude oil daily under the existing GVEA short-term contract. AS 38.05.183(e)(1).

b. A disposal to GVEA will have a favorable effect on the economy of the state because it will ensure that the cooperative's members continue to benefit directly from lower electric rates than would otherwise be possible. Each consumer to whom GVEA provides electric service is a member of the cooperative. Profit margins are allocated back to the consumer owners, all of whom are Alaska residents. The cooperative's goal is to provide dependable electrical service to its member-owners at the most economical price.

GVEA is regulated by the Alaska Public Utilities Commission. Over the past year, GVEA has experienced increased consumer need represented by an addition of 2,700 new households. GVEA currently employs 174 people (25 more workers than last year) to bring electric service to more than 50,000 Alaskans. AS 38.05.183(e)(2).

c. An in-state refiner, MAPCO, will be favorably impacted by the proposed GVEA contract. MAPCO's assigned right to purchase 5,000 bpd of state royalty oil enables MAPCO to refine many products for Alaskans in addition to turbine fuel for GVEA. The 5,000 bpd of royalty oil also assists MAPCO in meeting the feedstock requirements of its soon-to-be-expanded refinery. MAPCO may also sell or exchange the resulting return oil (so long as the price discount on turbine fuel provided to GVEA remains materially unaltered) to acquire more oil from TAPS near its Fairbanks refinery.

Although MAPCO will benefit from the proposed GVEA contract, it will not receive a windfall. Because of the \$.30 premium, MAPCO will likely pay more for the assigned oil than it does under its own state royalty oil contract. Further, MAPCO's Exhibit A agreement to pay most of any Amerada Hess liabilities arising under the proposed GVEA contract precludes it from passing on Amerada Hess adjustments to GVEA, as it would otherwise do. AS 38.05.183(e)(3).

d. GVEA is uniquely able to use its royalty oil purchases to allow it to supply electrical energy to more than 50,000 Alaskans who currently enjoy price benefits directly attributable to the cooperative's purchase of state royalty oil. AS 38.05.183(e)(4).

e. The state is now highly dependent on oil revenues and will continue to depend on oil revenues in the future. The price term of the proposed sale protects the state's interest by ensuring that revenues from this sale will exceed the in-value alternative. AS 38.06.070(a)(1).

f. The local and regional needs of the Fairbanks area for electrical supply are met by service provided by GVEA to its member owners. The assignment agreement with MAPCO also helps satisfy local and regional needs for petroleum products. AS 38.06.070(a)(2).

g. The continued operation of GVEA, with the attendant payroll and secondary benefits, will have a positive and desired effect on the citizens of the state. While this disposal will likely not result in new capital investment or development, it will enable the efficient use of existing investment and development and contribute to the requirements of a refinery planned for expansion. AS 38.06.070(a)(3).

h. The projected social impacts of a disposal to GVEA are anticipated to be favorable. The benefits presently received from the operation of the electrical cooperative will continue. AS 38.06.070(a)(4).

i. Any additional costs and responsibilities which could be imposed upon the state and affected political subdivisions are likely to be minimal. AS 38.06.070(a)(5).

j. Local and regional consumption of both fuel oil-fired electricity and refined petroleum products will be directly and favorably affected by the GVEA disposal. Local labor markets will continue to benefit through employment opportunities at both GVEA and MAPCO. AS 38.06.070(a)(6).

k. Environmental effects resulting from the proposal will be negligible, if any, since the facility is already in existence. AS 38.06.070(a)(7).

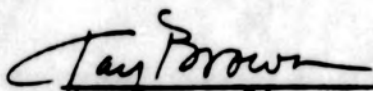
l. The proposed disposal will help existing commercial private enterprise and patterns of investments by assisting in the continued operation of the GVEA cooperative and providing, through assignment, royalty oil to the North Pole Refinery for processing into refined products. AS 38.06.070(a)(8).

In accordance with 11 AAC 03.060(b), the weight given to the applicable criteria in determining the maximum benefit to Alaska citizens must be addressed. In making this finding the Department first assured itself that the state would not lose money by making a disposal to GVEA. Once so assured, other benefits attendant to the disposal were examined. If the price offered did not assure the state at least what it would have received had it left the oil in-value then the sale would not, in the Department's view, serve the state's best interests. For this reason the greatest weight in this disposal was placed on AS 38.05.183(e)(1), the cash value offered. After the cash value offered, the greatest weight was given to the projected benefits of using the oil in the state to directly benefit Alaskan citizens through lower electric rates.

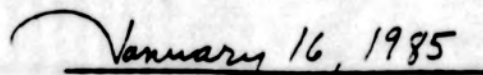
VII. Conclusion.

By the terms of the proposed contract, the state is guaranteed the litigation-adjusted in-value price for its oil as well as a premium on each barrel. The additional premium assures that the state is not initially receiving less for its oil than if it elected to take its royalty share in money at the weighted average of the Prudhoe Bay lessees' reported prices. Should the Amerada Hess litigation be resolved in the state's favor, the state will be entitled to reimbursements resulting from the retroactive price adjustments provided for in the contract, with MAPCO holding the major responsibility for that potential liability. The satisfactory price terms of the proposed contract, coupled with associated direct and secondary benefits for Alaska citizens, supports the decision to waive competitive bidding.

The foregoing facts and analysis support my final finding that this disposal is in the best interests of the state and that it maximizes benefits to Alaska citizens.



Kay Brown, Director
for Esther C. Munnicke
Commissioner



Date

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

THIS AGREEMENT is entered into as of February 8, 1985 by and between THE STATE OF ALASKA ("Seller") and GOLDEN VALLEY ELECTRIC ASSOCIATION INC., an Alaskan Electric Cooperative Corporation, hereinafter referred to as "Purchaser".

**ARTICLE I
DEFINITIONS**

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

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

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

1.3 "Effective Date" shall have the meaning set out in Article VI.

1.4 "Leases" means the Oil and Gas leases which are subject to the terms of the Unit Agreement.

1.5 "Lessee" means any person owning a working interest in any of the Leases.

1.6 "Month" means the period beginning at 12:01 a.m., Alaska Standard Time, on the first day of the calendar Month and ending at the same time on the first day of the next succeeding calendar Month.

1.7 "Oil" or "crude oil" shall have the same meaning as the word "Oil" under the Unit Agreement.

1.8 "Point of Delivery" shall have the meaning set out in Section 2.4.

1.9 "Royalty Oil" means the Oil which the Seller may take in-kind (amount) as its royalty under the Leases whether or not Seller has elected to take or is taking that royalty in-kind.

1.10 "Daily Royalty Oil" means the quantity of Royalty Oil produced by the Lessees each day.

1.11 "Unit Agreement" means the Prudhoe Bay Unit Agreement effective April 1, 1977, by and between Seller and the Lessees, as amended from time to time.

1.12 "TAPS" means the Trans Alaska Pipeline System.

ARTICLE II

SALE OF ROYALTY OIL

2.1 Quantity. Seller agrees to sell to Purchaser and Purchaser agrees to buy from Seller that amount of Oil equal to 2.667% of the Daily Royalty Oil (Maximum Quantity"). Upon at least nine (9) Months written notice to Seller, Purchaser may increase or decrease the amount of Oil to be tendered by Seller at the Point of Delivery, but the amount tendered by Seller under this Agreement shall not exceed the Maximum Quantity. Purchaser recognizes that Seller must normally give six (6) Months notice under the Unit Agreement (or ninety (90) days if the amount increased or decreased is less than ten (10) percent of the current nominations) to increase or decrease the amount of Daily Royalty Oil to be taken in-kind. It is understood and agreed that the volume of Daily Royalty Oil available to Seller will vary and may be interrupted from time to time, and depends upon a variety of factors, including the rate of production from the Leases. Seller disclaims and Purchaser waives any representation, covenant or warranty, expressed or implied, as to the specific quantity or the total or daily, Monthly, average, or aggregate volume of Royalty Oil to be sold or tendered under this Agreement. Seller warrants that it has good title to the Oil tendered under this Agreement. Seller shall hold Purchaser harmless from all liens, encumbrances and valid adverse claims that may affect the Royalty Oil at the time the Royalty Oil is tendered to Purchaser.

If Seller underlifts or stores Royalty Oil at Prudhoe Bay, or if Seller recovers underlifted or stored Royalty Oil, the quantity of Oil tendered under this Agreement shall be calculated as if no Royalty Oil was underlifted or stored or recovered.

2.2 Quality. The Oil sold shall be the same quality as the Royalty Oil delivered by the Lessees to the Seller at the Point of Delivery. It is understood and agreed that the quality of the Oil sold may vary from time to time. Seller disclaims, and Purchaser waives, any guarantee, representation, or warranty, either expressed or implied, of the merchantability, fitness for use, or suitability for any particular use or purpose, or otherwise, of any of the Oil delivered under this Agreement or as to any specific, average or overall quality or characteristic of Oil to be sold or tendered under this Agreement.

2.3 Price of the Royalty Oil. The price for the oil tendered under this Agreement shall be equal to the amount that Seller would have received from its Lessees for the Royalty Oil tendered if that royalty had been payable in money (taken in value) rather than taken in kind plus a premium of \$0.30 per barrel plus the Field Cost Allowance incurred by that oil as determined under the Prudhoe Bay Royalty Settlement Agreement (dated April 1, 1980 for reference purposes only), which was entered as part of a final judgment dated August 13, 1980 in State of Alaska, et al v. Amerada Hess Corp., et al., (Superior Court for the State of Alaska, First Judicial District at Juneau) ("Amerada Hess") ("Settlement Agreement") ("Purchase Price"). The Purchase Price shall be determined by Seller based upon the reports submitted by the Lessees for royalty purposes or, when those reports are unavailable, incomplete, or inaccurate, upon information submitted by the Lessees for production tax or other tax purposes, as may be adjusted from time to time as provided in this Agreement. Buyer will only be entitled to review or request material or information which is not confidential under state law or regulation.

The method, basis and amount of royalty due Seller when it takes its royalty in value from the Leases is presently the subject of litigation in Amerada Hess. One of the issues involved is the proper method to be used by the Lessees in calculating the state's royalty when the royalty is payable in money (in value). Until there is a resolution of that dispute through judicial resolution or settlement, the Purchase Price will be based upon the calculation of an amount per barrel equal to the per barrel volume weighted average of the in-value prices reported by the Lessees to Seller for royalty purposes or, when the royalty reports are unavailable, incomplete, or inaccurate, upon information submitted by the Lessees for production tax or other tax purposes, plus \$0.30 per barrel plus the Field Cost Allowance as determined under the Settlement Agreement. Upon final non-appealable resolution of each of the various issues that are or will be involved in Amerada Hess, adjustments will be made to previous payments in accordance with each resolution.

If additional amounts are owed by Purchaser to Seller, interest on those amounts will be paid at a variable interest rate which is the higher of: (1) the reference rate as may be announced from time to time by The Bank of America, San Francisco, California, plus three percent (3%); or (2) the rate of return as is realized from time to time in the investment of the State of Alaska's general fund. Amounts owed from Seller to Purchaser shall be repaid at the rate set out in Article 5.6. Buyer will not voluntarily intervene or otherwise participate in Amerada Hess unless Seller expressly consents to that participation in writing. A settlement of Amerada Hess will be binding upon Buyer whether or not Buyer agrees with or consents to the terms of that settlement.

If any applicable law of the United States of America or any rule or regulation promulgated by a federal agency will, in the judgment of Seller, operate to prohibit or prevent Seller from receiving the full amount due under the above provision, Purchaser's obligation to pay the amount of the Purchase Price in excess of the amount permitted will be suspended or adjusted to the minimum extent required for Seller to comply with that law, rule or regulation.

Either party shall have the right to reopen this Agreement, as to price only, during the Month of July, 1987 and every two years thereafter for the purpose of negotiating a new price for the Royalty Oil to be paid under this Section 2.3. The right to reopen may be exercised by either party by giving to the other party thirty (30) days prior written notice. Upon receipt of a notice to reopen, the parties will promptly commence good-faith negotiations in an attempt to establish a new price. In the event that a new price is not agreed to by the parties within ninety (90) days of the effective date of the notice to reopen, either party may terminate this Agreement upon nine (9) Months written notice to the other. The price for any Oil tendered during any such period pending termination shall be calculated as set out hereinabove or as agreed to in a previous reopener. If a new price is agreed to by both parties, such new price shall be effective for Oil tendered in the Month following agreement by the parties on the new price.

2.4 Point and Time of Delivery. Simultaneous with receipt of its Royalty Oil from its Lessees, Seller shall tender the Oil to Purchaser at the point at which Seller receives the Royalty Oil from its Lessees. That point as presently agreed to by Seller and its Lessees in Section 2.3 of the Settlement Agreement is the custody transfer meters into TAPS at Prudhoe Bay.

2.5 Passage of Title and Risk of Loss. Title and risk of loss to the Oil sold under this Agreement shall pass from Seller to Purchaser for all purposes when Seller tenders the Oil at the Point of Delivery.

2.6 Purchaser's Responsibility. Purchaser shall be responsible for the Oil after passage of title. Purchaser will indemnify and hold Seller harmless from and against any and all claims, costs, damages (including reasonably foreseeable consequential damages), expenses or causes of action arising from or in connection with any transaction or event which relates to the crude Oil after title has passed to Purchaser.

2.7 Transportation Arrangements. Purchaser shall make all necessary arrangements for transporting the Oil sold under this Agreement from the Point of Delivery, including satisfaction of line fill obligations and storage tank bottom requirements of TAPS, if any. If and as requested by the Seller, and

at the time or times requested by Seller, Purchaser shall submit specific information concerning the arrangement it has made for transportation of the Oil sold under this Agreement through and away from TAPS and for the resale or other disposal of the Oil. Such information may include the specific tenders of Oil made to TAPS and identification of tankers which will transport the Oil. In addition, Purchaser will provide Seller, if and as requested by Seller, with satisfactory evidence or reasonable assurance of the existence and continuing validity of adequate arrangements for the transportation or disposal of the Oil subject to this Agreement. Failure to provide information, evidence or assurances requested will, at Seller's election by notice to Purchaser, be a material default under this Agreement.

2.8 Absolute Obligations. The obligations of Purchaser to accept, pay for, and arrange for the transportation of the Oil tendered or sold under this Agreement are absolute and will not be excused or discharged by the operation of any disability of Purchaser, event of force majeure, impracticability of performance, change in conditions, or any other reason or cause.

2.9 Date of First Delivery. The date of First Delivery will be four (4) Months after the Effective Date unless Seller, in its sole discretion, sets an earlier date.

2.10 Performance Guaranty and Reservation Fee. If Purchaser does not take the Maximum Quantity on the Date of First Delivery, Purchaser shall pay to Seller, in addition to the Purchase Price, an amount equal to 1.25% of the Purchase Price per barrel per day on the difference between the Maximum Quantity and the actual quantity tendered to and accepted by Purchaser ("Actual Quantity") for each day Purchaser does not take the Maximum Quantity on and after the Date of First Delivery. The payment of this fee shall end on the day that Purchaser accepts delivery of the Maximum Quantity. When Purchaser accepts the Maximum Quantity, all of the amounts paid under this Article 2.10 will be allowed to be credited against future payments for Oil tendered under this Agreement except for an amount to be retained by Seller equal to .75% of the Purchase Price per barrel per day on the difference between the Maximum Quantity and the Actual Quantity for each day Purchaser did not take the Maximum Quantity on and after the Date of First Delivery. If

Purchaser should thereafter decrease the amount of Oil to be tendered under this Agreement, Purchaser shall pay to Seller, in addition to the Purchase Price, an amount equal to .75% of the Purchase Price per barrel per day after the date that the decrease in the amount of Oil to be tendered by Seller takes effect on the difference between the Maximum Quantity and the Actual Quantity.

2.11 In-State Processing. Purchaser agrees that all Oil purchased under the terms of this agreement shall be processed or burned in the State of Alaska. As used in this Agreement "processed or burned in the State of Alaska" means the following described uses or a use substantially similar to those uses, which provides an equivalent benefit to GVEA's consumers. Purchaser has assigned its Oil to MAPCO PETROLEUM Inc. for processing the crude oil into a fuel usable at Purchaser's generating station. Under this arrangement, Purchaser is assured of a dependable supply of fuel, which assists Purchaser in providing uninterrupted electrical service to its consumers. Purchaser also receives from MAPCO a lower refining charge or processing fee which Purchaser passes directly through to its consumers in the form of reduced electric rates. If Purchaser's arrangement with MAPCO ever fails to yield these benefits, Purchaser has a commitment from the Rural Electrification Administration for mortgage funds to be made available to pay for the prompt conversion of Purchaser's generating units so that the Oil could be burned as fuel by Purchaser without first being processed. Upon such conversion, Purchaser could again provide its consumers with a dependable supply of electricity at a cost lower than otherwise possible.

Purchaser's continued receipt of a dependable supply of fuel upon terms that allow Purchaser to provide its consumers with electricity at a cost significantly lower than otherwise possible is a material element of this agreement. Purchaser's failure to process or burn in the State of Alaska as defined in this Agreement the Oil tendered under this agreement will, at Seller's option, constitute a material default under this agreement. However, Seller may, at its option, waive the in-state processing or burning requirement in whole or in part, if Seller is satisfied that the waiver would not be contrary to the underlying intent of the other provisions of this Agreement.

ARTICLE III
REPRESENTATION AND OBLIGATIONS OF PURCHASER

Purchaser warrants, represents, and agrees:

3.1 Good Standing and Due Authorization. Purchaser is, and at all times during the operation of this Agreement shall remain, a corporation organized and existing under and by virtue of the laws of the United States or of any state, territory or the District of Columbia, and qualified to do business in, and in good standing with, the State of Alaska. Purchaser has all necessary corporate power to enter into this Agreement and to perform its covenants and obligations under this Agreement. All necessary corporate action has been taken to authorize Purchaser's entering into this Agreement and performing its covenants and obligations under this Agreement.

3.2 Financial Condition. The financial information submitted to Seller is complete and correct and fairly presents Purchaser's financial condition at the time the information was submitted to Seller. The financial information was prepared in accordance with generally accepted accounting principles consistently applied. Since the date the information was submitted, the condition, business and properties of Purchaser have not been materially adversely affected in any way. Purchaser agrees to inform Seller immediately if during the term of this Agreement there is any material adverse change in the condition, business, or properties of Purchaser which would have an appreciable adverse effect on Purchaser's ability to perform under this Agreement. Purchaser, in addition, will immediately inform Seller of any significant change in ownership of either Purchaser or any of its affiliates or parent company, and of any change in Purchaser's operations or agreements, which would appreciably affect Purchaser's performance under this Agreement.

3.3 Financial Statements. As soon as possible after the end of each fiscal year of Purchaser, and in any event within one hundred twenty (120) days thereafter, Purchaser will furnish to Seller, at Purchaser's sole cost and expense, a report or a complete copy of a report in a form to be prescribed from time to time by Seller which will include Purchaser's balance

sheet as of the close of the fiscal year and the income statement for that year, prepared in each case in accordance with generally accepted accounting principles consistently applied by certified public accountants of recognized standing. For purposes of complying with this Article, Purchaser may submit, and Seller will accept, the annual report of the Golden Valley Electric Association, Inc.

3.4 Option to Purchase Return Oil. If Purchaser assigns Oil purchased under this agreement for fuel usable in the present configuration of its generating station, there may remain a portion of Oil or Oil products which will not be processed for consumption in-state ("Return Oil"). This Return Oil may be shipped through TAPS. Return Oil shipped through TAPS becomes intermingled with unprocessed crude oil so that when the Return Oil is picked up in Valdez it is identical to the common stream crude oil shipped through TAPS. A shipper of Return Oil presently is, and may continue to be, liable for the payment of a quality bank adjustment differential based upon the resulting degradation of TAPS common-stream crude ("quality penalty").

Purchaser grants Seller an option to purchase all the Return Oil. For the purposes of determining the volume of Return Oil for which Seller may exercise its option to purchase under this Agreement, that volume shall be a proportion of the Oil tendered under this Agreement equivalent to the ninety (90) day rolling weighted average, determined monthly, of the ratio of total refined products produced to total refinery charge. Seller shall exercise this option by giving Purchaser nine (9) months' advance written notice. The notice shall specify the date delivery will commence and the point of delivery to Seller. Thereafter Seller may terminate the purchase of Return Oil by giving nine (9) months' advance written notice.

Seller shall have the option to take title to the Return Oil either at the tanker flange inlet in Valdez, Alaska, or at the MAPCO refinery outlet to the Golden Valley Pipeline at North Pole, Alaska. The per-barrel Return Oil purchase price shall be the full cost to Purchaser or Purchaser's assignee at the point of redelivery minus any "quality penalty" which had or would attach, which will be paid by Purchaser. Purchaser or Purchaser's assignee will assign all necessary shipment rights to guarantee delivery to Seller at

Seller's designated delivery point and to facilitate the reinjection into and transportation of the Return Oil through TAPS.

Purchaser or Purchaser's assignee shall furnish Seller or the Seller's designee, on or before the tenth day of the month following the month of delivery, a provisional invoice covering the Return Oil delivered to Seller or Seller's designee in the preceding month. The price of the Return Oil to Seller or Seller's designee shall be the price paid by Purchaser for Oil tendered under this Agreement for the month preceding delivery. The Seller or the Seller's designee shall make payment to Purchaser or Purchaser's assignee on or before the twentieth day of the month following the month of delivery. The initial billing may be adjusted in a subsequent month's invoice as more accurate or complete information concerning the quantity and Purchase Price of the Return Oil delivered each Month is available. Subsequent adjustments to the Return Oil initial billing shall also be made for Amerada Hess as specified in Section 2.3 and for other adjustments as specified in Section 5.5.

The amount of all sums which are not paid when due under this option or which are subsequently determined to be due under an adjustment, shall bear interest from the date accrued until paid in full at a variable rate per annum equal to the reference rate as announced from time to time by the Bank of America, San Francisco, California, plus one and one-quarter percent (1.25%) per annum, provided, however, that any interest due on an adjustment made as a result of the Amerada Hess litigation shall be at the same rate charged by Seller under Section 2.3.

The option to purchase Return Oil will remain in effect for the term of this Agreement. Failure to exercise this option for any period of time will not affect the Seller's right to exercise the option at a later time. This option, in whole or in part, and for any term, shall be freely assignable by Seller and such assignment shall release Seller from all obligations to receive or pay for the Return Oil sold under this option, provided, however, that Purchaser or Purchaser's assignee shall have the right to demand of an assignee of the Seller reasonable security for the Return Oil sold to that assignee. If authorized in an assignment by Seller, that assignee shall have the further right freely to assign that option, however, that assignment shall

not release the assignee (or any subsequent assignee) of any responsibilities or liabilities to Purchaser or Purchaser's assignee unless agreed to by Purchaser or Purchaser's designee. Seller shall provide Purchaser or Purchaser's designee with written notice of any such assignment.

ARTICLE IV MEASUREMENTS AND TESTS

The quantity and quality of the crude Oil sold under this Agreement shall be determined at the Point of Delivery. Procedures and methods for measuring and metering the Oil sold under this Agreement shall be in accordance with the practices then in effect at Prudhoe Bay, Alaska.

ARTICLE V PAYMENTS AND ACCOUNTING

5.1 Billing. Seller will send to Purchaser, on or before the 10th (tenth) business day of each Month after delivery of Oil, an invoice statement of account of all Royalty Oil estimated to have been measured at the custody transfer meter into TAPS and tendered to Purchaser under this Agreement during the immediately preceding Month according to the best information available to Seller, the estimated Purchase Prices applicable to those deliveries, and the total amount due ("initial billing"). The estimates will be made by Seller according to the best information reasonably available to Seller. Seller may render its initial billing to Purchaser based in part upon information reported by the Lessees to Seller and information published by the U.S. Government. Seller shall thereafter adjust its initial billing under this Article as soon as more accurate information concerning the quantity and Purchase Price of Oil delivered each Month is available. Seller, however, shall not be required to adjust the initial billing prior to the sending of the next Month's invoice statement of account.

5.2 Initial Adjustment. After the Monthly invoice under Section 5.1, the subsequent Monthly invoice will also state Seller's initial adjustments to be made, if any, to the invoice rendered in the immediately preceding Month, in accordance with any additional or more accurate information which may have become available to Seller. Whether or not initial adjustments are made, however, subsequent adjustments may be made under Section 5.5.

5.3 Payment. Purchaser will make payment of each amount billed under this Article within ten (10) days after receipt of the invoice statement of account. Payment shall be made without any deduction, set off, or withholding, by wire transfer of immediately available funds to Seller's account at the following address:

First Pennsylvania Bank Philadelphia
ABA No. 031000024
For Credit to State of Alaska
Account No. 07/089250/00
Attn: Catherine Hess

Payment may be made in such other manner or to such other address as Seller may specify in the invoice statement of account or by other written notice. All other payments to be made under this Agreement shall be paid in the same manner. If payment is due on a Saturday, Sunday, or legal holiday of the place where payment is to be received, payment shall be made on the next following business day. It is recognized that Seller may bill, and that Purchaser will pay, amounts that are based upon confidential information held or received by Seller. If confidential information is used as the basis for a billing, then upon request Seller will furnish Purchaser with the certified statement of the Commissioner that the amounts billed are correct based upon the best information available to Seller. If a dispute concerning a bill arises, Purchaser agrees to pay the full amount billed by Seller, pending final resolution of the dispute.

5.4 Payment to Lessee. Purchaser, at the request of Seller in the invoice statement of account or otherwise in writing, shall pay all or any portion designated by Seller of that payment required to be made to one or more of the Lessees at an address or addresses and in the manner designated by Seller. The payment will be made within the time limit specified in Section 5.3. Seller may authorize and designate a third party to make the request and

designate the amount, manner and place of payment under this provision. Unless otherwise specified, the balance of the payment due, if any, and payment for subsequent Months, shall be made in accordance with Section 5.3.

5.5 Subsequent Adjustments. Purchaser acknowledges that more accurate information concerning the quantity of or Purchase Price for Royalty Oil tendered may subsequently become available to Seller. In the event that any such information should subsequently become available to Seller, Seller shall promptly furnish a corrected invoice statement of account to Purchaser and the parties will adjust the amount billed and pay or refund the amount of those adjustments. In the event that Seller should render a corrected invoice to Purchaser, any amount to be refunded from Seller to Purchaser or paid from Purchaser to Seller will be paid within fifteen (15) days after the date of the corrected invoice. However, when the adjustment concerns an amount last invoiced more than sixty (60) days before the corrected invoice, the amount will be paid by Purchaser or refunded by Seller, as the case may be, in equal Monthly installments over the same period of time as that over which the adjustment accrued or six (6) Months, whichever is the shorter period. No adjustment will be made more than twelve (12) Months after the date of the last original invoice to which the adjustment relates, except for adjustments resulting from: (i) regulatory or court proceedings (including appeals) commenced or pending during that twelve (12) Month period, whether or not Seller or Purchaser is a party to the proceeding, or (ii) bona fide audits by Seller of any Lessee(s) commencing at any time during the period six (6) years after the date of the last invoice to which such adjustment relates, or any resolution of disputes arising out of those audits. Adjustments due to audits or regulatory proceedings or court proceedings may be made at any time. The provisions of this Section 5.5 will survive any termination of this Agreement.

5.6 Interest. Except for adjustments made upon resolution of Amerada Hess under Article 2.3, the amount of all sums which are not paid when due under this Agreement or which are subsequently determined to be due under an adjustment under Section 5.5, shall bear interest from the date accrued until paid in full at a variable rate per annum equal to the reference rate as announced from time to time by the Bank of America, San Francisco, California, plus one and one-quarter percent (1.25%) per annum.

5.7 Late Payment Penalty. If Purchaser fails to make full payment within one (1) day of the date that payment is due, then in addition to the amount due plus interest from the date that payment was due until the date of payment, Purchaser will pay an amount equal to one percent (1%) of the amount owed.

5.8 Payment to Third Parties. Seller may direct that Purchaser pay any amount due or which may become due directly to a third party in the manner and time as may be directed by Seller in written notice to Purchaser if, in the Seller's sole discretion, the payment to the third party will assist Seller in monitoring or enforcing this Agreement.

ARTICLE VI

TERM

This Agreement shall become effective upon execution by the parties and after enactment of legislation by the State of Alaska (including approval by the Governor) approving this Agreement. This Agreement shall be null and void if it is not so approved by September 30, 1985. Subject to the other provisions contained in this Agreement, Seller's obligation to sell and Purchaser's obligation to buy Royalty Oil shall begin as provided above, and shall end June 30, 1995. As used in this Article, "enactment of legislation" is as defined in AS 01.10.070(f)(4).

ARTICLE VII

DEFAULT OR TERMINATION

7.1 Default. If any one or more of the following events ("Events of Default") occur, then at Seller's option, Seller may terminate or suspend its obligation to tender and sell Royalty Oil and proceed to exercise any one or more of the rights and remedies provided in this Agreement:

- (i) At any time, Purchaser (a) repudiates any of its covenants or obligations under this Agreement, or (b) fails, within five (5) Days after written request from Seller, to provide Seller with written affirmation of this Agreement and of Purchaser's intention to perform under this Agreement (together with evidence or assurances of transportation arrangements pursuant to Section 2.7 reasonably satisfactory to Seller); or
- (ii) Purchaser does not pay in full any sum owed under this Agreement at the time when payment is due; or
- (iii) Purchaser fails to observe or perform any of its other covenants and obligations under Article II; or
- (iv) Purchaser does not perform any act required or contemplated under this Agreement and either: (a) the nonperformance continues for more than thirty (30) days after Seller has notified Purchaser of Purchaser's nonperformance; or (b) Purchaser had failed to perform the same or any other act required or contemplated under this Agreement during the immediately preceding twelve (12) Month period; or
- (v) There is a material adverse change in Purchaser's condition, business or property which appreciably affects the ability of Purchaser to perform any of its obligations under this Agreement, and Purchaser is unable to give Seller adequate assurance of continued performance either within five (5) days of a request for such an assurance or within such other shorter time period as Seller may reasonably request under the circumstances; or
- (vi) Any representation or warranty made by Purchaser in this Agreement proves to have been false or incorrect in any material respect at the time that the representation or warranty was made.

7.2 Failure to Pay Debts. If at any time Purchaser becomes unable to pay any of its debts when those debts are due, or should otherwise become insolvent (without regard to how that insolvency may be evidenced), Purchaser will immediately give notice of that fact to Seller. Whether or not that notice is given, if Purchaser becomes unable to pay any of its debts when those debts are due or should otherwise become insolvent, Seller's obligation to tender and sell Oil under this Agreement will automatically and immediately terminate without any requirement of notice or other action by Seller; however, Purchaser will nevertheless be and remain liable for payment and performance of all of its obligations and covenants under this Agreement with respect to Oil actually tendered by Seller to and after any such termination. Within thirty (30) days after receipt of Purchaser's notice or, if no notice is given, after Seller otherwise becomes aware (as determined in Seller's sole discretion) of Purchaser's insolvency, Seller will have the right, upon written notice to Purchaser, to reinstate all of Seller's and Purchaser's obligations under this Agreement retroactively to the date of termination.

7.3 Seller's Remedies. Upon the occurrence of any Event of Default or if Seller's obligation to tender and sell Oil under this Agreement is terminated or suspended under Sections 7.1 and 7.2, all obligations of Purchaser accrued but not otherwise due and payable under this Agreement will immediately be due and payable in full. In addition, Purchaser will indemnify and hold Seller harmless from and against all other liability, damages (including reasonably foreseeable consequential damages), costs, losses and expenses (including reasonable attorneys' fees and disbursements) incurred by Seller and arising out of the Event of Default, termination, or suspension. Seller shall have the right cumulatively to exercise any and all other rights and remedies and to obtain all other relief available under applicable law or at equity, including mandatory injunction and specific performance. Seller, upon occurrence of any Event of Default, in its sole discretion, may arrange for any disposition to third parties of Royalty Oil to be tendered and sold under this Agreement. Upon the occurrence of any Event of Default, Purchaser may, in Seller's discretion, be released from the obligations set forth in Article 2.11 (In-State Processing) until the Event of Default no longer exists or the obligation of Purchaser to take Oil under this Agreement expires. Upon occurrence of any Event of Default Seller makes arrangement f

disposition to third parties of Oil, or if Purchaser is released from Article 2.11, whether or not this Agreement is terminated, Purchaser will nevertheless be and remain liable to Seller for the full amount of the Purchase Price for that Oil in excess of the Purchase Price over any amount or amounts received by Seller on account of that disposition, net of the expenses of that disposition and for all other costs, expenses (including reasonable attorneys' fees and disbursements), and losses incurred by Seller and arising out of the Event of Default or disposition.

7.4 Purchaser's Exclusive Remedies. Upon any breach of, or default in, the due and timely observance or performance of any of Seller's covenants or obligations under this Agreement, Purchaser acknowledges and agrees that Purchaser's remedies will not include a temporary restraining order or preliminary injunction preventing Seller from taking any action with regard to the Royalty Oil which is the subject of this Agreement.

ARTICLE VIII DISPOSITION OF OIL

8.1 Disposition of Oil Upon Default or Termination. Purchaser acknowledges and agrees that under the Unit Agreement and Leases, Seller's election to take Royalty Oil in-kind can be revoked or reversed only upon the satisfaction of various conditions, including the giving of six (6) Months notice to return all or more than ten percent (10%) of Seller's then current nominations. Purchaser acknowledges and agrees that Seller's election to invoke its rights to return to taking its Royalty Oil in value on less than six (6) Month's prior notice, or to attempt to secure a waiver of any condition or requirement, is at Seller's sole and complete discretion. Notwithstanding termination of this Agreement for default or for any other reason, including expiration or termination under any provision contained in this Agreement, Purchaser shall continue to take and purchase Seller's Royalty Oil in the amount and for the price set forth in this Agreement for up to four (4) Months following termination of this Agreement if Seller, in its discretion, so requires.

8.2 Inability to Receive Oil. If for any reason Purchaser is unable or refuses to accept or receive any Oil tendered under this Agreement, Purchaser shall nevertheless be and remain responsible for the disposal of that Oil and for paying Seller for the Oil as though it had been received and accepted by Purchaser unless Seller, in its sole discretion, elects to waive this requirement. In order to secure the obligations of Purchaser under this Section 8.1 and under Section 2.8, Purchaser shall, if and as Seller may request from time to time, assign to Seller all right, title and interest of Purchaser under any nominations, leases, agreements, contracts, charter parties and other arrangements for the transportation of the Oil sold under this Agreement through and away from the Trans Alaska Pipeline System; provided, that Seller shall not have any liability or obligations under any such nominations, leases, agreements, contracts, charter parties or other arrangements unless, and to the extent that, Seller shall actually exercise its rights to succeed to Purchaser's interest thereunder and shall obtain the benefits thereof.

8.3 No Right to Storage or Underlift. Purchaser waives and disclaims any interest or right that it may assert to storage of Royalty Oil, including by underlift or other means, to which Seller is or may come to be entitled under the Leases or any other agreement.

ARTICLE IX

WAIVER

The failure of either party to insist upon strict performance of any provision of this Agreement shall not constitute a waiver of, or estoppel against, asserting the right to require that performance in the future. A waiver or estoppel in any one instance shall not constitute a waiver or estoppel with respect to a later breach of a similar nature or otherwise. A course of performance established by a party shall also not estop the other party from complaining of a later breach similar in nature.

ARTICLE X
VALIDITY

If any provision or clause of this Agreement or application of this Agreement to any person or circumstance is held invalid, that invalidity shall not affect other provisions or applications of this Agreement which can be given effect without the invalid provision or application. If, however, an invalidity should operate to impair any material right or remedy of a party to this Agreement, that party may terminate this Agreement by notice to the other.

ARTICLE XI
FORCE MAJEURE AND CHANGE IN CONDITION

11.1 Effect of Force Majeure. Except for Purchaser's obligations to make payment of money for Oil tendered under this Agreement and except for Purchaser's obligations to accept and dispose of Royalty Oil, neither party shall be liable for any failure to perform the terms of this Agreement when the failure is due in whole or in substantial part to force majeure. The term "force majeure" as applied to this Agreement shall mean Acts of God, strikes, lockouts and industrial disputes or disturbances, civil disturbances, arrests and restraints from rulers or people, interruptions by government or court orders or by present or future orders of any regulatory body having or asserting jurisdiction, acts of the public enemy, wars, riots, blockades, insurrections, inability to secure materials by reasons of allocations promulgated by authorized governmental agencies, epidemics, landslides, lightning, earthquakes, fires, storms, floods, washouts, explosions, breakage or accident to machinery or lines of pipe, freezing of wells or pipelines, or any other event or condition, whether of the kind herein enumerated or otherwise, not within the reasonable control of the party claiming the benefit of this excuse. If, however, any material obligation of Purchaser is excused or suspended because of a claim of force majeure for a period of three hundred sixty-five (365) successive days or more, Seller will have the right to terminate this Agreement. Prior to Seller exercising its right to terminate this Agreement Seller and Purchaser shall enter into good faith negotiations to restore, to the fullest extent possible, Seller and Purchaser to the

benefits and obligations that existed under this Agreement before the occurrence of the force majeure condition.

11.2 Responsibility. Upon the occurrence and discovery of an event providing the basis for a claim of force majeure, the party making a claim shall notify the other party to this Agreement of its claim of force majeure. Upon the occurrence of an event constituting force majeure, that event shall, so far as possible, be remedied with all reasonable diligence and dispatch. Except for Purchaser's obligations to make payment of money for Oil tendered under this Agreement and except for Purchaser's obligation to dispose of Oil, the obligations of the disabled party to perform under this Agreement, insofar as they are affected by that force majeure, shall be suspended from the time that force majeure occurs and for so long as the disability caused should have continued had the party claiming the existence of the force majeure remedied the event providing the basis of the claim of force majeure with reasonable diligence and dispatch, and for no longer. The settlement of strikes or lockouts or industrial disputes or disturbances will be entirely within the discretion of the party having the difficulty, and the above requirement that any force majeure shall be remedied with diligence and dispatch shall not require the settlement of strikes, lockouts, or industrial disturbances by acceding to the demands of any opposing party therein when such course is inadvisable in the sole discretion of the disabled party.

ARTICLE XII

NOTICES

12.1 Method. All notices, requests, demands or statements shall be in writing, and may be delivered personally to the party to be notified or may be sent by registered or certified United States mail, postage prepaid, with a return receipt requested to such party. Notice deposited in the mail in this manner shall be effective upon the expiration of seven (7) days after it is so deposited. Notice given in any other manner shall be effective only if and when received by the addressee. For the purposes of notice, the addresses of the parties to this Agreement shall be as follows:

If to Seller: State of Alaska
Commissioner of Natural Resources
Pouch "M"
Juneau, Alaska 99811

and

Commissioner of Revenue
Pouch "S"
Juneau, Alaska 99811

and

Director, Division of Oil and Gas
Pouch 7-034
Anchorage, Alaska 99510

If to Purchaser:

GOLDEN VALLEY ELECTRIC ASSOCIATION, INC.
P.O. Box 1249
Fairbanks, Alaska 99707

and (as long as the right to Oil is assigned thereto)

Vice President-Supply
MAPCO PETROLEUM Inc.
P.O. Box 645
Tulsa, Oklahoma 74101-0645

12.2 Change of Address. Each party may change its address for notice by giving notice of the change.

ARTICLE XIII RULES AND REGULATIONS

This Agreement is subject to all present and future valid laws, orders, rules and regulations of the United States, the State of Alaska, and any duly constituted agency thereof.

ARTICLE XIV
SOVEREIGN POWER OF THE STATE

This Agreement and its covenants shall not be interpreted as a limit on the exercise by the State of Alaska of any of its sovereign or regulatory powers, whether conferred on the State by constitution, statute or regulation, including but not limited to, its regulatory power over the Leases. The exercise by the State of Alaska of any sovereign or regulatory power will not operate or be deemed to enlarge any rights of Purchaser or to limit or impair any obligations or liability of Purchaser under this Agreement, except for state statutes enacted after the effective date of this Agreement which have a direct and significant adverse effect on the ability of Purchaser to perform an obligation under this Agreement other than the obligations to accept, dispose, and pay for Royalty Oil tendered under this Agreement.

ARTICLE XV
SECURITY

Thirty (30) days prior to the Date of First Delivery, Purchaser shall cause to be furnished to Seller evidence that an irrevocable stand-by letter of credit for the benefit of Seller effective by Date of Delivery, will be issued by a state or national banking institution of the United States which is a member of the Federal Deposit Insurance Corporation and has an aggregate capital and surplus of not less than One Hundred Million Dollars (\$100,000,000), or other banking institution acceptable to Seller in its sole discretion. The principal face amount of the letter of credit shall initially be Five Million, Three Hundred Sixteen Thousand Dollars (\$5,316,000). The letter of credit shall be substantially in a form satisfactory to the Commissioner, but in any event shall not require any documents to be submitted in support of drafts drawn against this letter of credit other than the certified statement of the Commissioner or her designee and the Attorney General of the State of Alaska or his designee that Purchaser is liable to Seller for a sum equal to the amount of such draft, and that that sum is due and payable in full and has not been timely paid. In the event that Seller should have reasonable grounds for asserting any claims against Purchaser

under this Agreement and does assert those claims in an aggregate amount in excess of the aggregate principal face amount of the letter of credit then in effect, Purchaser shall upon Seller's request (whether or not Purchaser may deny, reject or otherwise resist such claims) cause the principal face amount of the letter of credit to be increased by an amount equal to the excess. The principal face amount of the letter of credit shall also be automatically increased by Purchaser without request from Seller whenever the face amount is less than the expected Purchase Price of sixty (60) days of Oil tendered under this Agreement, to an amount equal to the expected Purchase Price of sixty (60) days of Oil tendered. The principal face amount of the letter of credit may be decreased by Purchaser upon approval of Seller (which approval will not be unreasonably withheld) if the face amount is more than the expected Purchase Price of sixty (60) days of Royalty Oil tendered under this Agreement, to an amount equal to the expected Purchase Price of sixty (60) days of Royalty Oil tendered. The Commissioner may accept such other or additional security as she, in her sole discretion, considers adequate to protect Seller.

ARTICLE XVI
PREFERENTIAL HIRING AND NON-DISCRIMINATION

Purchaser agrees to hire and employ Alaska residents and Alaska companies to the extent they are available, willing and qualified for all work performed in Alaska that is performed under or in connection with this agreement. As used in this agreement "Alaska resident" means an individual who has resided in the State for one year at the time of hiring or employment and "Alaska companies" means those companies who are incorporated in the State of Alaska or whose principal place of business is in Alaska.

If this provision is determined to be unconstitutional by a court of competent jurisdiction, then Purchaser agrees to hire and employ Alaska residents and Alaska companies to the extent such preferential hiring is determined to be constitutional.

ARTICLE XVII
APPLICABLE LAW

17.1 Alaska Law. This Agreement shall be governed by and construed in accordance with the laws of the State of Alaska, excluding any conflict-of-law rule or principle which might refer such construction to the laws of another state or country.

17.2 Submission to Jurisdiction. Any legal action or proceeding arising out of or relating to this Agreement or for the enforcement of the covenants or obligation of either party must be instituted in a State court of general jurisdiction sitting in the State of Alaska, and Purchaser hereby irrevocably submits to the jurisdiction of that court in any such action or proceeding.

ARTICLE XVIII
WARRANTIES

The purchase and sale of Royalty Oil under this Agreement is subject only to the warranties of Seller expressly set forth in this Agreement and Seller disclaims and Purchaser waives all other warranties, expressed or implied in law, whatsoever.

ARTICLE XIX
AMENDMENT

This Agreement may be supplemented, amended or modified at any time, but only by written instrument duly executed by the parties to this Agreement. Any material amendment to the contract which appreciably reduces the consideration received by the State requires prior approval of the Legislature of the State of Alaska.

ARTICLE XX
SUCCESSORS AND ASSIGNS

No assignment, pledge or encumbrance of this Agreement shall be made by either party without first obtaining the written consent of the other party. The Commissioner may grant such consent on behalf of the Seller. The Commissioner shall have sole and complete discretion in granting or denying a proposed assignment, pledge or encumbrance. Subject to the above requirements in this Article, this Agreement will be binding upon and inure to the benefit of each of the parties and its successors and permitted assignees. In addition, if Purchaser gains or acquires a controlling interest in an entity which has an agreement with Seller for the sale of Royalty Oil ("Other Agreement"), then Seller, at its option and on one year's notice, may require Purchaser to terminate either this Agreement or the Other Agreement. The choice of which Agreement to terminate will be Purchaser's. Purchaser may request that Seller waive this option in advance of Purchaser gaining a controlling interest in an entity which has an agreement with Seller for the sale of Royalty Oil. The Commissioner has sole and complete discretion in granting or denying the requested waiver.

ARTICLE XXI
HEADINGS

Headings used in this Agreement are for convenience only and shall not affect the construction of this Agreement.

ARTICLE XXII
RECORDS

22.1 Preservation of Records. Purchaser will preserve and maintain all books, accounts, and records relating to or arising out of the performance of this Agreement, including but not limited to the purchase or sale of Royalty Oil and its refined products, for a period of six (6) years. Purchaser will also maintain and preserve all similar books, accounts, and records of which

it has possession belonging to those third parties with whom it contracts for the performance of various parts of this Agreement. Neither Purchaser nor Seller shall be required to retain any records for more than six (6) years unless retention of such records is specifically required by applicable law or regulation. Purchaser shall either maintain its records within the State of Alaska or make such records available to Seller at Purchaser's principal office in the State of Alaska within thirty (30) days after written request by Seller.

22.2 Inspection of Records of Parties. Purchaser and Seller will accord to each other and to their authorized agents, attorneys, and auditors during reasonable business hours access to any and all property, records, books, documents, and indexes directly relating to Purchaser's or Seller's performance of this Agreement and which are under the control of the party from which access is desired so that the other party may inspect, photograph and make copies of that property, records, books, documents and indexes. In no event, however, shall Seller be required to disclose any information, data, or records which are required to be held confidential by state law or regulation. If the information obtained by Seller may be held confidential under state or federal law or regulation, Purchaser may request that that information be held confidential by Seller.

ARTICLE XXIII INTERPRETATION OF TERMS AND CONDITIONS

In the event that there is a disagreement about the meaning or application of a word, term, or condition in this Agreement, Purchaser will present the arguments supporting its view in writing to the Commissioner for her consideration. The Commissioner will subsequently, within a reasonable time, issue a finding on the meaning or application of the disputed word, term, or condition, setting forth the basis for her conclusions. Purchaser agrees to accept findings by the Commissioner under this Article as long as there is substantial evidence supporting the Commissioner's findings. None of the above shall empower the Commissioner to set the price of the Oil should such price become subject to renegotiation pursuant to Section 2.3.

DATED this 8th day of February 1985.

SELLER:

THE STATE OF ALASKA

Commissioner,
Department of Natural Resources

PURCHASER:

GOLDEN VALLEY ELECTRIC ASSOCIATION, INC.

By

Michael P. Kelly
General Manager



Alaska State Legislature

House of Representatives

Pouch V
State Capitol
Juneau, Alaska 99811

HOUSE SPECIAL COMMITTEE ON OIL AND GAS

January 18, 1985

Rep. Mike Davis, Chairman

AGENDA

Appoint committee vice chairman.

Finalize committee meeting time and place.

Determine topics to be discussed by the Division of Oil and Gas on Jan. 25.

Finalize committee budget request.

Determine session agenda for the committee.



Official Business

Alaska State Legislature

HOUSE SPECIAL COMMITTEE

ON OIL AND GAS

Pouch V
State Capitol
Juneau, Alaska 99811

The 14th Legislature has the opportunity to take an aggressive role in clarifying state policy regarding several oil and gas issues. Policy questions include the state's position regarding the disposition of royalty oil, the state's future revenue structure, federal and state offshore conflicts, and the establishment of a state oil-contingency fund.

The following outline presents topics of discussion to be considered by the House Special Committee on Oil and Gas.

Royalty Oil Legislation

1. Dept. of Natural Resources proposed legislation regarding AS 38.05.183, allowing for continuing short-term competitive sales without legislative approval.
2. Dept. of Natural Resources amendment regarding AS 38.05.035(e), removing this reference to the best interest finding.
3. Clarification of best interest regarding proposed MAPCO contract.
4. Policy position toward in-value versus in-kind use of royalty oil.

Alaska Crude Oil Export Ban

1. Possibility of gaining an exemption from the Export Administration Act, in light of national security and lowering the federal deficit.

Federal and State Conflicts

1. Disputed federal-state Beaufort Sea boundary, and the determination of ownership of lease revenues in state and federal escrow accounts.
2. Benefits to Alaska of maintaining royalty oil windfall profits tax exemption.
3. Effects of the Deficit Reduction Act upon revenue sharing from mineral revenues on federal lands.
4. Effects of attempts by the federal government to limit severance tax levies.

Litigation

1. Legislative direction regarding the TAPS settlement case.
2. Possible litigation regarding artificially low West Coast oil prices since 1977.

Taxation

1. Review of taxation of oil and gas revenues.

Natural Gas

1. Probability of gas line construction in light of deregulation and present market conditions.
2. Probability of constructing a small-diameter gas line from Prudhoe Bay to Fairbanks.

Contingency Fund

1. Desirability of establishing a contingency fund in the event of a break in service of oil flowing through the Trans-Alaska Pipeline.