

ALASKA LEGISLATURE COMMITTEE FILES 1987-1988 86/2

4981 HRES HB 471

33

HOUSE RESOURCES COMMITTEE
3/16/78
TAPE 71
TESTIMONY OF MILTON LIPTON
CONSULTANT FOR W. J. LEVY & ASSOCIATES

The higher royalty is bid the sooner it becomes a burden against the value of production therefore and the more onerous it becomes.

I'll come back to that in the context of abatement of royalty later on. But for this reason the royalty itself is an unattractive aspect of costs. Royalty bidding per se is an unattractive bidding variable excepting possibly in highly proven areas where the people who are bidding competitively have reasonably good expectations as to what would be found and fairly good knowledge of what costs may be and therefore instead of the royalty bidding a shot in the dark the royalty bidding can be made on a reasonably intelligent basis.

Not regarded as attractive among the alternatives.

I turn now from the bidding variables to the subject of the reduction of royalties. The commissioner's right to abate the royalty when this is a means of prolonging the productive life of the field. That's the item on page six subparagraph (d) and Jack Roderick referred to it and I feel obliged to speak about it because he said Mr. Lipton was going to talk about it. The commissioner has had that right to abate royalty under

your statute for some time. Our quarrel with this is not that the commissioner has the right to abate royalty it's that if you have in your lease sale the royalty as the bidding variable you have created an incentive for the competing companies to bid as high a royalty as possible and then in effect what you are doing is you are bringing the point of time when this high royalty that you invited into bid now becomes onerous and he's threatening to stop production. So he goes to the commissioner and he says let us abate this royalty. I think there is an incongruity between inducing the companies to bid the highest royalty possible and then creating the situation where they are almost driven to ask sooner than they otherwise would have for possible abatement of royalty and you're faced with a dilemma that if you don't abate the royalty it may result in premature abandonment of production before you would like it. It's not just abandoning production it becomes even more important earlier in the life of a field when the company is considering should we invest money to sustain the life of the field. Re-working the wells, for example, all the other things, drilling some in-field wells on a lease. Then the high royalty may become a burdensome thing and he decides that he is not going to make that investment unless the royalty is abated.

I think that one has to consider very carefully whether you use royalty bidding or the abatement of royalty or whether you stipulate in advance wherever royalty is the bid variable there

shall not be abatement of royalty. You create an incongruity between these two clauses in the lease.

AGC 1115684

20655

✓ w/ Bruce etc. re Ct. intro of inciv's bill -

HB 471 Eason, Carol, Larry, Mike K, Royce, Feinberg.

Admin / DO+G said no way on this part inciv among others.
want to avoid mkg Leon the villain -

bought leases below value - Phillips did a memo on it - avail. soon -
Jim wants Ed to do 2 things -

simple cover letter - impress. to pres. rev. implications on royalty
valid to look at # fields that wd be affected - Seal Island
wd only be aff'd - recov. exp. of 350 mn bbls (recov.) -
don't know how the infrastruc wd be constructed - figure
on some rate of return (10% min) - produce profile -

for Seal minimum 28.6 m barrels -

wd rev. no roy's parts this century -

would hist'l data - antiz. bonuses w/ another bidding system in
1979 -

by using NPS - prob; saved \$314 m - just on bonuses -

→ foregone revenues - 78.5 m. (A-H); Perm. Fund losses -

→ when do leases lapse? 1990/91 -

will rebid them later?

→ who does Sec. 3 affect? - Exxon, Nizakuk, Pt Thompson - nonprod.
West Sak - Mike K. ↳

→ Lipton testig on 78 AS 38 A's allowing NPS - get it. Steve Porter

technical problems of admin. .. potential of productivity no royalties at all. -

dev't acc'd already inc'd in 2 A-H leases ~ \$97/8 m - 6 wells at about \$20m ea. + interest.

all costs - can't really figure - used only pot'l problem -
The incentive to gold-plate -

→ any precedent for this anywhere?

Swape has info DOR doesn't

FOIA req. to Gov's Ofc / DNR / DOR for info they have?

HB 421 = Pt Thomson -

→ cheat showing - foregone revenue - who else bid on tracts?

cost of this bill in bbls

pot'l revenue if leases are not dev'd by 1990

→ lease provision regarding the expiration or loss if not prod'g or unitized - what other lease provisions?

→ Texas Eastern has asked to abrogate work commitment

→ confidence in reserve estimates? Hess est'd 600+ -

Texas Eastern is a gas pipeline co. in Houston, didn't know about Hess proposal -

Shell

unit history - unit req'ts - A-H will be operator?

prob. 100,000 bbls/day -

→ who wants the pipeline?

Hess - what to expect -

→ will ind. that outside fed'l acq'g might be worth 1/5 + dev'g w/ this strike -

→ fiscal note? PF impact

cd displace royalties leaving oil in TAPS if dev'd soon

Oil and Gas Topics of Interest

Discussion topics for the Senate Oil and Gas Committee. Prepared February 1988 by the Division of Oil and Gas.

Leasing Schedule--New Sales. This year the department added four sales to the state's five-year oil and gas leasing program (1988 to 1992). The four new sales are North Slope Sale 66A (exempt), Cook Inlet Sale 67A (exempt), White Hills Sale 61 and Beaufort Sea Sale 68. The state's 1988 leasing schedule is shown below.

Sale Number	Sale Name	Proposed Date
54	Kuparuk Uplands	January 1988*
55	Demarcation Point	June 1988
66A	North Slope Exempt	June 1988
52	Beaufort Sea	January 1989
56	Alaska Peninsula	June 1989
67A	Cook Inlet Exempt	June 1989
59	Cook Inlet	January 1990
57	North Slope Foothills	June 1990
64	Kavik	January 1991
65	Beaufort Sea	June 1991
61	White Hills	January 1992
68	Beaufort Sea	June 1992

*Sale 54 was held January 26, 1988--see discussion below.

North Slope Sale 66A will be the state's first sale to take advantage of AS 38.05.035(e)(7), which was passed by the legislature last year. The statute allows the department to hold an exempt acreage sale without writing a best interest finding if one has been issued previously for the area within 36 months of the sale date.

The proposed Sale 66A acreage is located within an area known as the "Kuparuk Uplands," and includes acreage previously leased, but subsequently relinquished, from sales 45A, 47 and 48. The department received a number of industry requests for an exempt acreage sale in this area. The sale area includes approximately 219,913 acres of land.

Cook Inlet Sale 67A will include eligible lands in the Cook Inlet region that have been specifically nominated by industry. The actual lands that will be offered in the sale have not yet been identified by the department. Eligible lands in the lower Susitna Valley, on the Kenai Peninsula and submerged lands in Cook Inlet may be offered.

Proposed Lease Sale 61 was previously scheduled for September 1990. The sale area consists of approximately 875,000 acres located immediately south of acreage offered in sales 47, 48 and 54. The Trans-Alaska Pipeline System lies to the east of the sale area and to the west is the Colville River.

Proposed Sale 68 consists of approximately 393,000 acres of state-owned tide and submerged lands offshore of the NPRA, including some submerged lands whose ownership is currently disputed. The sale is centered around Barrow, extending from Tangent Point in the east to near Nulavik in the west. Beaufort Sea lands offered previously in sales 50, 52, and 55 may also be offered for lease in the sale.

The state's current leasing schedule provides for two to three sales each year. It is a more modest schedule than leasing programs proposed during the early 80's, when at least three sales, and as many as five sales, were offered each year. The department believes the current schedule provides an optimum number and mix of sales. It is composed of sale acreage near areas of known oil production, primarily on the North Slope and in Cook Inlet. That acreage has the greatest likelihood for holding future oil and gas discoveries. The schedule will allow industry to devote its tight exploration budgets to areas of state land having the best oil and gas potential.

Kuparuk Uplands Sale 54. Sale 54 was held January 26, 1988. It included 89 tracts, or approximately 421,808 acres, lying between the Colville River and the area of Kuparuk Uplands Sale 48. It also included acreage in the Colville River delta.

The sale utilized cash bonus bidding with a fixed 12.5% royalty, and included a 15% Exploration Incentive Credit (EIC). The sale earned \$4.6 million, or an average bid of \$13.83 per acre. Eleven bidding groups submitted 164 bids on 72 tracts.

Lessees will earn EIC's at a rate of \$300 per foot drilled for the first exploratory well per tract, provided that credits do not exceed 15% of the total exploratory well costs. The credits must be earned and used within five years of the effective date of the lease.

Camden Bay Sale 50 Litigation. The department currently is involved in litigation concerning Camden Bay Sale 50, held June 30, 1987. The lawsuit was brought by the Trustees for Alaska, Northern Alaska Environmental Center, National Parks and Conservation Society, Wilderness Society and Sierra Club.

Briefs were filed in Superior Court late last year. The judge assigned to the case is Judge John Bosshard, III. To date, the court has not set a date for oral argument. The department, however, anticipates resolution of the suit within the next few months.

Demarcation Point Sale 55. Sale 55 is the next sale on the state's leasing schedule. The sale is located offshore of the Arctic National Wildlife Refuge (ANWR) between the Hulahula River (west of Kaktovik) and the Canadian border. The department anticipates that industry interest in the sale will be high. The preliminary finding for the sale was issued February 4, 1988. Following public and agency review of the preliminary finding, the final finding and decision of the director will be issued on April 25, 1988.

As with Sale 50, the department expects that a decision to proceed with Sale 55 will be controversial. Debate will center on the sale's effect on ANWR and the importance of the sale area for bowhead whales and subsistence hunting.

The division currently is conducting its pre-sale evaluation in order to select an appropriate bidding method for the sale. The division's evaluation of the sale area will be aided greatly by data from two exploratory wells drilled nearby on adjacent lands and new computer equipment recently purchased to process seismic data.

The two exploratory wells that have been drilled near the Sale 55 area are Tenaco's Aurora well and the KIC well in ANWR. In November 1987, Tenneco, in partnership with 10 other companies, began drilling its Aurora prospect just beyond the three-mile limit, about 22 miles northeast of Kaktovik. Because of an agreement with the Department of the Interior, the division has access to the information from this well as it is being drilled. The KIC well, which is located about 14 miles southeast of Kaktovik, was drilled by the Arctic Slope Regional Corporation in association with Chevron, Standard Alaska Production Company and BP Alaska. The confidentiality period for the KIC well is scheduled to end April 24, 1988. At that time, the division will have access to the well data. The data from both wells are important because they provide the only available direct information about the subsurface of the sale 55 area and adjacent lands.

With the purchase of the new computer equipment, the division now has the capability of digitally reprocessing seismic data in order to improve its quality. The equipment will allow the division to conduct a more in-depth analysis of available data, and should greatly improve the pre-sale evaluation for this and all other future sales.

Leasing & Development in ANWR. A number of bills have been introduced in Congress concerning oil and gas development on the ANWR coastal plain. H.R. 39 (Rep. Udall) and S. 1804 (Roth, Bradley and Chafee) would prohibit oil and gas leasing on the coastal plain by including it in the national wilderness system. On the other side, S. 1217 and H.R. 1082 (respectively, the Murkowski-Stevens and Young bills), would open ANWR to oil and gas leasing. H.R. 3601, sponsored by Congressman Jones (N. Carolina), is an "exploration-only" bill--allowing only four exploratory wells to be drilled on the coastal plain, the results of which would be evaluated before determining whether or not to proceed with leasing. A bill recently introduced by Senator Johnston (Louisiana) authorizes a competitive oil and gas leasing program in ANWR, but provides Alaska with only 50% of the resulting revenues. A possible amendment to that bill, by senators Wirth, Evans and Bumpers, calls for a two to three year moratorium on leasing, until a comprehensive study can be conducted to provide Congress with adequate energy policy information. Another House bill expected to be introduced by Congressman Anderson (California) calls for leasing, but also reduces the state's share of the revenue from 90% to 50%.

Division personnel have testified before U.S. Congressional committees and Alaska legislative committees in support of opening ANWR to further exploration and development. These committees include the U.S. House Subcommittee on Water and Power Resources, the U.S. Senate Committee on Energy

and Natural Resources, and the Alaska Senate and House Resources Committees and the Joint Oil and Gas Committee. Personnel have also given presentations to various professional and civic organizations, including the Resource Development Council (RDC), the Free Committee of the Anchorage Women's Auxiliary, and the Public Lands Committee of the Interstate Oil Compact Commission (IOCC).

The division also is providing information to interested individuals and organizations to explain the state's position on the ANWR land exchanges.

Beaufort Sea Lease Boundary. The jurisdictional boundary dispute between the state and federal governments (United States v. Alaska, No. 84 Original in the United States Supreme Court) continues to be a problem when planning lease sales in the Beaufort Sea; nor is there any indication how long it will be before the dispute is resolved. The suit has been pending for eight years. Moreover, the parties have now waited more than one year for the Court's Special Master to issue his recommended decision in the case. Beyond the Special Master's recommendation, the Supreme Court's briefing, argument and decision process must occur before a final judgment is rendered.

Eventually, a judicially decreed state/federal boundary in the Beaufort Sea will result from resolution of United States v. Alaska. In the interim, the division is attempting to negotiate an agreement with the federal government that would fix existing state/federal leasing boundaries in the Beaufort Sea. These efforts were initiated in 1986, and discussions continued throughout 1987. The division would like to avoid the costs and legal uncertainty associated with adjusting existing lease boundaries after the state/federal boundary is fixed by judicial decree. Accordingly, we believe the state/federal jurisdictional boundary should be established using the same geographic data used to determine any previously agreed-on state/federal leasing boundary; or, at a minimum, the leasing boundary should be fixed for the life of the oil and gas lease.

Lacking a decreed state/federal boundary, the state and federal governments must negotiate an agreement under Section 7 of the Outer Continental Shelf (OCS) Act to lease the disputed lands. Section 7 agreements have been successfully negotiated for OCS sales 71 and 87. However, no agreement could be reached for Sale 50. As a result, the state pulled back its seaward leasing boundary to a conservative position to avoid the possibility of an injunction to delay the sale. Currently, discussion is occurring between the Minerals Management Service (MMS) and the division for a Section 7 agreement for OCS Sale 97. However, given the extremely late invitation by MMS to enter into a Section 7 agreement for Sale 97, it is unlikely that our differences can be worked out in time to sign an acceptable agreement prior to the final notice of sale, which is due in March 1988.

Use of Explosives in the Marine Environment. The use of explosives for seismic operations in the marine environment was prohibited by the state in 1975. In 1985, the division published a report stating that the limited use of explosives is necessary if reasonable quality seismic data are to be obtained from areas where non-explosive energy sources are ineffective. The department concluded, however, that insufficient information was available

concerning the effects of explosives on juvenile salmon to warrant a change in state policy at that time. The division's report recommended that a test be conducted to determine the effects of explosives on juvenile salmon.

In 1986, the Alaska Oil and Gas Association (AOGA) conducted a study to test the effects of linear explosive detonations on juvenile fish, especially salmonoids. The results of the AOGA study were published in October 1987 and concluded that the best estimate of the lethal range for juvenile salmon from a linear explosive is 150 meters. The study recommends that more information about the seasonal distribution of fish be gained in Alaskan waters where linear explosives are needed to acquire seismic data.

The division is presently reviewing the study, and will request comments and recommendations from the departments of Fish & Game and Environmental Conservation. Following the study's review, the division will recommend to the cabinet whether or not to pursue a change in state policy. If a decision is made to pursue a change in state policy, the division will hold public meetings in affected communities to explain its recommendation and to solicit comments on the subject.

Royalty Oil Export. Last year, the department successfully concluded a one year contract to sell for export 97% of the state's daily royalty oil production (3,600 barrels per day) from the fields on the west side of Cook Inlet. Those fields are Granite Point, MacArthur River, North Trading Bay and Trading Bay fields. Delivery began in July of 1987 to Chinese Petroleum Corporation of Taiwan, which agreed to pay a premium of \$1.83 per barrel above what the state would have received had it left the oil in-value. The department issued a solicitation for offers in January 1988 for another one year contract, which will follow the expiration of the Chinese Petroleum Corporation contract. The proposal calls for a new contract to be signed by June 1988, with a date for first delivery scheduled for December 1988.

Free Trade with Canada. There is broad agreement between the governments of Canada and the United States to assure the freest possible bilateral trade in energy, including nondiscriminatory access for the United States to Canadian energy supplies and secure market access for Canadian energy exports to the United States. The federal government has agreed to allow exports of Alaskan oil to Canada, up to 50 thousand barrels per day on an annual average basis, subject to a condition that such oil be transported from Alaska on U.S. flag ships. Given the restrictions on state government (such as the six month notice provision under the terms of the lease to the producers), it is improbable that state royalty oil will be part of this export at least in the near term.

AOGA Stipulation Study. In response to a request by AOGA, the state's resource agencies, in conjunction with the Division of Governmental Coordination, are preparing a letter explaining the state's rationale behind various stipulations attached to oil and gas development projects. The letter is presently in draft form. Once finalized, the letter will represent the consensus of the resource agencies concerning the need for the state's lease

stipulations. The letter also will invite AOGA, if it disagrees with the state's rationale, to conduct a stipulation cost/benefit analysis for the state's further consideration.

Oil and Gas Incentives Analysis. The division recently concluded a review of ways to stimulate petroleum activity in the state. In addition to reviewing the state's taxing and leasing policies as well as incentives currently available in Alaska, the division reviewed legislative and administrative incentive programs enacted by the other petroleum producing states and Canadian provinces to provide exploratory and development-related assistance to the oil industry.

As most "lower 48" oil producing states have a limited land base, the majority of states that enacted incentive programs utilized severance tax relief as the primary means to stimulate petroleum activity. In addition, because most of the production in these states comes from stripper wells (ie. wells that produce less than 10 barrels of oil per day (bopd)), the states generally adopted programs designed to postpone the abandonment of this production and ultimate loss of oil reserves.

Canadian provinces have adopted a variety of incentive programs, ranging from outright credit or cash grant programs to royalty/tax holidays and price sensitive sliding scale tax formulas to stimulate economic activity. Currently, the royalty/tax rates in Canadian provinces vary from 10% to 44% depending on the type of oil.

In comparison with the other oil producing states and provinces, Alaska is already providing numerous incentives for exploration and development. In the wake of declining world oil prices, the state has offered some of the lowest minimum bid and per acre rental terms available for competitive leases issued anywhere in the United States. In addition, most of the state's leases are encumbered with only the statutory minimum one-eighth royalty share of oil for the state. The state also has offered Exploration Incentive Credits (EIC's) [AS 38.05.180(i)] in state oil and gas lease sales, most recently in Sale 54, to share some of the risks associated with drilling exploratory wells. Since 1982, the state has granted credits amounting to almost \$36.6 million.

In the past, the state also had a discovery royalty provision which reduced, for a period of ten years beyond the date of discovery, the state's royalty to 5% from production allocated to a lease where the discovery involved a new geological structure (see Laws of Alaska, 1959, Chapter 169, page 243). The discovery royalty program was an incentive to encourage oil companies to come to Alaska, then a newly formed, cash-poor state. It generated significant drilling activity in Cook Inlet and thus accelerated oil and gas exploration and development of state lands. The discovery oil provision was repealed in 1969, but remains in effect for some state leases issued before 1969. To date, ten wells have been certified as discovery wells, and two applications are pending certification.

Finally, under AS 38.05.180(j), the state may allow for a reduction of royalty to compensate for increasing cost in the later stages of production decline. The reduction, however, cannot be granted until two years of initial production from a field has occurred. The lessee also must clearly show that

the revenue from all hydrocarbons produced from a field is insufficient to provide a reasonable rate of return with respect to the lessee's investment in the field.

NGL Settlements. A controversy has developed between the state and North Slope producers of the Prudhoe Bay, Lisburne and Kuparuk fields concerning the processing fee deducted from the reported value of sales gas and natural gas liquids (NGL's) produced from those fields. The controversy centers on what processing fee, if any, is deductible from the producer's royalty payments.

Three gas facilities are currently operating on the North Slope. These facilities, and particulars, are as follows:

- a. Prudhoe Bay facility: December 1986 startup; December 1987 production was 54,048 BPD NGL's.
- b. Lisburne Reservoir facility: June 1987 startup; December 1987 production was 2,206 BPD NGL's.
- c. Kuparuk Reservoir facility: April 1985 startup; December 1987 production was 3,625 BPD NGL's.

All three facilities also produce "dry" natural gas for unit use and marketing. The NGL's and some natural gas are being sold, and royalties are being reported to the state. The Prudhoe Bay gas facility also produces fluids (e.g., ethane and propane) used in enhanced oil recovery operations in the field.

North Slope producers have submitted pricing proposals to the state for the NGLs and sales gas processed by these facilities. The pricing proposals would be used to determine a "lease plant split" processing allowance for each operator. The proposed processing allowances suggested by these producers are:

- a. Sadlerochit facility:
 - ARCO: \$0.30/MCF (Sales Gas)
\$4.39/bbl (NGLs)
 - Exxon: \$0.45/MCF (Sales Gas)
\$2.54/bbl (NGLs)
 - Standard: \$0.75/MCF (Sales Gas)
\$7.34/bbl (NGLs)
- b. Lisburne facility:
 - ARCO: \$0.32/MCF (Sales Gas)
\$19.21/bbl (NGLs)
 - Exxon: \$0.47/MCF (Sales Gas)
\$19.99/bbl (NGLs)
- c. Kuparuk River facility:
 - ARCO: \$0.24/MCF (Sales Gas)
\$7.79/bbl (NGLs)

The processing allowance, if accepted by the state, would be deducted on a per barrel basis from the royalties paid to the state by each producer. In the case of the Lisburne facility, however, the proposed processing allowance is greater than the reported selling price of crude oil at Pump Station #1. Consequently, the difference between the proposed processing allowance and the crude oil price would then be deducted from the total royalties owed the state from all production.

The state has issued a formal notice of its disagreement with the processing allowances proposed for the Prudhoe Bay and Lisburne facilities. The state's position concerning the Kuparuk River facility currently is being drafted. For the Prudhoe Bay facility, the state has proposed a deduction of \$0.31/bbl if the liquids are to be reported as NGL's. Alternatively, the state proposed a deduction of \$0.67/bbl if the liquids are to be reported as oil. The \$0.67/bbl figure represents the agreed to Prudhoe Bay oil field cost allowance. At Lisburne, the state has proposed a deduction of \$0.67/bbl, the standard oil field cost allowance in the Prudhoe Bay Unit.

Thus far, ARCO and Exxon have rejected the state's counter proposals. As both sides appear firm in their respective positions, resolution of the processing allowance proposals appears headed for litigation.

Niakuk and Endicott Discovery Royalty Certification Applications. On May 22, 1987, Standard Alaska Production Company filed an application for certification of its Sag Delta No. 4 well as a discovery in the Endicott reservoir. For administrative reasons, the application was processed in conjunction with a similar request for Standard's Niakuk No. 5 well, which was submitted on August 27, 1987. The affected leases were issued on January 24, 1967 at Competitive Oil and Gas Lease Sale 18, and consequently would qualify for discovery royalty under the statutes.

If approved, the royalty rate for production from each lease would be reduced from 12 1/2 percent to 5 percent for a 10-year period beginning from the date of each respective discovery. The reduced royalty period for the Endicott discovery lease (Sag Delta No. 4 well) would be from April 1, 1978 through March 31, 1988. Because production from this lease began in October 1987, the royalty reduction for the Endicott discovery lease would only be effective for about 6 months. The Niakuk reduced royalty period would be from May 1, 1985 through April 30, 1995. Although no oil has yet been produced from the Niakuk reservoir, a portion of the oil production from the Lisburne unit has been allocated to the Niakuk discovery lease.

STEVE COWPER
GOVERNOR



STATE OF ALASKA
OFFICE OF THE GOVERNOR
JUNEAU

JWS - J. Egan

January 28, 1988

Mr. Leon Hess
Chairman
Amerada Hess Corporation
1185 Avenue of the Americas
New York, NY 10036

Dear Leon,

This is a somewhat tardy reply to your proposal to provide tax and royalty relief for the Seal Island leases. I have decided against the proposal, and I want to explain my reasons.

First off, I appreciate the spirit in which this proposal was made. You and Ron were very clear about your objectives and realistic about the political implications that would attach. I like a direct approach and normally do things that way myself.

As you know, any decision I make in this area must reflect a state policy which applies to the whole industry. At this time there are a number of outstanding leases which were purchased at a time when oil price projections were more sanguine than they are today. Many of those leases provided for a net profit share in lieu of larger up-front bonuses, as was the case with Amerada Hess at Seal Island.

Your proposal would benefit the state because of the jobs which would be created. It's hard to tell about the effect on state revenues, which also translates into jobs. That would depend on a judgment as to whether TAPS would otherwise be filled to capacity; if so, the oil produced under this incentive program would displace other oil on which the state was receiving its regular revenues. For the next few years, I am informed that TAPS will probably be operating at its nominal maximum capacity of 2.1 million bpd. If that's right, then the effect will be close to a wash in terms of jobs, although my stated preference is for private-sector employment.

RECEIVED

FEB 03 1988

DIVISION OF OIL & GAS
ANCHORAGE, ALASKA

Mr. Leon Hess

-2-

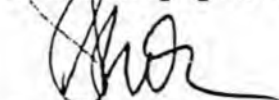
January 28, 1988

The political effects of this proposal must be assessed as well. While we are looking at the possibilities of incentives, given the current TAPS throughput the major producers are saying they don't want any of that kind of help. There is also the question of interference with the normal developmental order which is established mainly by relative cost. Thirdly, a lot of people don't want to establish any kind of incentive regime. They're already mad at the effect of the so-called "economic limit factor" legislation of 1981.

For the moment at least, my judgment is that when all the above factors are considered, a major departure from current policy isn't warranted. I know you and Ron disagree with this analysis but that's where I come down on it.

I hope things are otherwise well with you, the company, and the Jets, and I look forward to seeing you again in the near future.

Sincerely yours,



Steve Cowper
Governor

MEMORANDUM

State of Alaska

DEPARTMENT OF NATURAL RESOURCES
DIVISION OF OIL AND GAS

TO: James E. Earl
Director

DATE: February 19, 1988

FILE NO:

TELEPHONE NO: 762-2589

FROM: Ed Phillips
Petroleum Economist

SUBJECT: Minimum Fiscal Impacts
of the Hess Proposal as
Represented by HB 471.

HB 471 introduced by Representative Gruenberg appears to be a clone of an earlier proposal offered to the state by Leon Hess for royalty and tax relief at Seal Island. HB 471 would generalize the applicability of royalty and tax relief to other North Slope "reserves" particularly Pt. Thomson and West Sak. In an earlier memo the Hess Proposal and its cost in barrels of oil for the Seal Island prospect only was specifically analyzed. With minor changes that analysis is produced below. The issues raised in the analysis are still valid. The fiscal cost of applying the proposed statute could be substantial and the gains possibly chimerical.

As is often the case, the potential "costs" of the proposal are more easily discernible than the potential benefits. The potential "costs" of the proposal are the foregone royalties and taxes. These would amount to about 25 to 30% of the gross production for the period before capital recovery or December 31, 1999, whichever is less. These revenues would be forgiven during the peak production phase of the typical field. The potential benefits result from transforming fields from submarginal status to profitable. This transformation in itself does not assure that benefits equal or exceed costs. In some cases, the forgiveness may only shift forward by a year or two a particular field's development. In this case it is hard to argue the wisdom of the forgiveness. In other cases the forward shifting of development and production may be much more dramatic. Until we have more evidence of which phenomenon is more likely it will be exceedingly difficult to assess the potential benefits of this proposed legislation.

Assumptions

1. Recoverable reserves at North Star/Seal Island are estimated to be 350 million barrels. State leases have an estimated 80% of recoverable reserves. The remaining reserves are on federal leases.
2. Project must earn after tax 10% real rate of return to be feasible.
3. All state leases have 20% royalty rate.
4. Peak production at 100,000 barrels a day through first four years, then production declines at 15% per year. Total field life is 16 years.
5. Time value of production is evaluated at three interest rates, 5%, 10% and 15%.
6. Price assumed to be constant so that analysis is done in terms of barrels of oil. This is the index number for measuring costs.

Methodology

1. Compute the present value of production as of time zero. Then lag time zero for various delays that apply discount factors to the delays. The present value is stated in terms of "discounted" barrels. For example, the present value of 350 million barrels of oil produced over a sixteen year period at 5% discount equals approximately 217 million barrels of oil as a present value equivalent. At 10% this value drops to 192 million barrels, and at 15% 171 million barrels. (The method used for these calculations is readily found in Newendorp, Paul D. "Decision Analysis for Petroleum Exploration," Petroleum Publishing Company, Tulsa, Oklahoma, 1974, Appendix I, pp: 651-659.)
2. Payback (recovery of invested capital) was estimated by two methods. First, the "Rule of 72" was used. This "rule" allows one to estimate payback by dividing the rate of return into the number 72. For example, if a particular investment earns 10% per year, it will payback in approximately 7.2 years. The "Rule of 72" is a quick and dirty way to compute doubling times for compound interest rates. The other method used was to divide the rate of return into 100. This works reasonably well for uniform cash flows. (This method is illustrated in Megill, Robert E., "Exploration Economics," Petroleum Publishing Co., Tulsa, Oklahoma, 2nd Ed., 1979, pp. 83-84.) Finally, doubling times for compound interest were computed directly. These techniques will yield estimates of undiscounted payback on original investment, thus they represent minimal estimates of payback periods. Capital recovery calculations permit payback with imputed interest and represent a maximum estimate of payback.

This analysis does not forecast a rate of return for Seal Island. It only examines the conditional statement that if Seal Island earns X rate of return, then payback will take approximately Y years. This proposition is evaluated for 10 and 15 percent rates of return (ROR). This methodology can be used for any ROR.

3. "Cost" to the state is measured in terms of undiscounted oil as well as the present value of royalty barrels foregone during payback period under the North Star (Seal Island) proposal. This simple methodology can easily be extended to include severance taxes. The inclusion of these taxes adds about 50% to the annual cost estimates, but shortens the payback period. Another potential "cost" to the state is from the delay in development and production at Seal Island due to submarginal economics attributable to state's royalty and severance taxes. This delay cost is measured for 5, 10, 15 and 20 year delays, at 0, 5, 10 and 15% discount rates.
4. Caveat: This methodology is admittedly crude, but very little data are available to justify a more sophisticated, yet questionably more accurate approach. This approach will, at least, frame the discussion in more analytical terms.

Results

1. Given an assumed 350 million barrels of recoverable reserves, the state's 20% royalty share would be 56 million barrels of undiscounted oil. (This total could be as high as 84 million barrels with the inclusion of the severance tax.) In discounted barrels this claim drops to 34.6 million barrels at 5%, 30.7 million at 10% and 27.4 million at 15% if the field could start producing as of today.

Table I

Present Value Barrels
Royalty Share

Discount Rates	Delay Times					
	0 Years (millions of BBls)	5 Years (millions of BBls)	10 Years (millions of BBls)	15 Years (millions of BBls)	20 Years (millions of BBls)	
0	56	56	56	56	56	
5	34.6	27.1	21.2	16.7	13.1	Δ 8.1
10	30.7	19.1	11.8	7.4	4.6	Δ 7.2
15	27.4	13.6	6.8	3.4	1.7	Δ 5.1

2. The reality of Seal Island economics and construction schedules vitiate columns one and two as possibilities. The maximum gain to the state if the delay is reduced by 10 years, is equivalent to 8.1 million royalty barrels of oil (Column 3 minus Column 5 at a 5% discount rate). At discount rates of 10 and 15 percent the gain associated with expedited development is less.
3. What is the royalty "cost" to the state of waiting until payback in order to capture this "gain"? The cost depends upon the rate of return on investment. If the rate of return is 10%, simple payback can take from 7.2 years by the "Rule of 72" or 11.5 years if operators are allowed a 10% rate of return on their investment before payback is complete. This would imply a minimum of 76% of recoverable reserves or about 16.1 million present value royalty barrels (42 million actual barrels) would be produced at no royalty value to the state. The maximum estimate would be about 17.4 million royalty barrels (46 million actual barrels). This means that about 82% of the field's recoverable reserves would be produced before the state would begin to receive its royalty share. The "actual" barrel estimates were derived from the field's estimated production profile as stated in Assumption 4.

At higher rates of return, simple (interest free) payback is less onerous. Payback can be achieved in five years if the project earns 15%. With this ROR payback even with imputed interest of 10% is achieved in about eight years. The cost is between 12.5 to 15.6 million present value royalty barrels (28.6 million to 41 million actual barrels).

Including a severance tax forgiveness does not change the actual barrel sacrifice by the state, but it does increase the present value barrel cost. This result follows directly from the greater "upfront" sacrifice by the state at peak production rates. The implied gain is faster payback, hence earlier reimposition of the royalty and severance tax.

Thus, for the present value equivalent of approximately 16 to 17 million barrels, (42 to 46 million actual barrels) one could argue that production would be hastened by 10 years. But that would be giving the operator benefit of all of the best assumptions. What if, in reality, the state was only purchasing a year or two in expedited development? The cost is still the same, but the benefits decline considerably. Whereas costs were only double the benefits where production was hastened by 10 years (16 million cost, 8 million benefits), the benefits approach zero as the delay difference declines. Suppose allowing payback only reduced delay by 5 years from 15 to 10 years, then the gain is only 4.5 million present value bbls at most. (Column 3 minus Column 4.) If production was only affected by one year, the benefit is reduced to 1 million barrels. The cost is still 16 million barrels.

Some caveats are important. The preliminary results outlined here may be sensitive to assumptions about field size and decline rates. Given economics of scale and concomitant longer, peak production periods, it is likely that payback would occur earlier for a significantly larger field. (This effect would follow from a higher ROR associated with the larger field.) A rapid real increase in oil prices would also change this result by increasing the ROR. The relationship between the ROR and payback would not change.

Conclusion

1. For a minimum royalty oil cost of 28.6 to 46 million barrels the state may get something.
2. Unless real oil prices substantially increase, the state will receive no royalty payments from the proposed development in this century.

MEMORANDUM
DEPARTMENT OF NATURAL RESOURCES

State of Alaska
DIVISION OF OIL AND GAS

TO: James E. Eason
Director

DATE: January 8, 1988

FILE NO:

TELEPHONE NO: 762-2589

FROM: Edward L. Phillips
Petroleum Economist

SUBJECT: Hess Proposal, or
"Foregone Conclusions"

One point overlooked in the Amerada Hess discussion is the "savings" already transferred to Amerada Hess by the state as a result of the net profit bidding system employed in Sale 30. At the date of the sale (12/12/79), price expectations were extremely bullish. The Iraq/Iran war had been underway for a few weeks and spot oil prices, reflecting the uncertain outlook of the war, were in the \$35.00 to \$40.00 a barrel range. Market contract prices were moving up, and many price forecasters saw no end in sight. For example, the March 1980 Department of Revenue forecast projected the price of Saudi Marker Crude at \$46.43 in 1985, \$57.91 in 1990, and \$143.17 in 1996 (a perfect example of the power of compounding). Parenthetically, yesterday's (7 January 88) Saudi spot price was \$16.40. Markets have little tolerance for the compounding process. This forecast was not, by any means, off the wall--but represented a "middle of the pack" estimate.

The petroleum potential of the Beaufort Sea looked extremely attractive (profitable) with the price expectations of the period. Against this background, the winning bidders at Seal Island paid a total of \$19.2 million in bonus payments for the state tracts overlying the prospects. Amerada Hess paid \$6.9 million for its two tracts. In addition, the net profit share (NPS) bids ranged from 85.26% to 93.2%.

At that time, our analysis indicated that the same tracts, if sold on a bonus bid basis with a 20% royalty, were worth an estimated \$333 million, and possibly much more. The state/federal price assumptions used for the presale analysis were relatively conservative.

One could argue that the NPS bidding system permitted "savings" to the winning bidders of approximately \$314 million. Specifically, Amerada Hess paid \$6.9 million for tracts the state estimated to be worth about \$120 million. Thus, NPS bidding saved Amerada Hess over \$113 million, and possibly much more. In fact, it is not clear that Amerada Hess possessed the financial resources to win the tracts under a conventional leasing system. The major North Slope operators (ARCO, Sohio, Exxon) had deeper pockets, and were clearly better positioned to bid higher cash bonuses had the cash bonus been the bidding variable for the state tracts, as it was for the adjacent federal tracts overlying the Seal Island structures.

As a conceptual exercise, one can compute the true savings to Amerada Hess by looking at what the \$113 million could have earned them over the eight year time period since the sale. At a 10% rate of return (ROR), Amerada Hess would have earned almost \$129 million since the sale. If their ROR was 15%, their earnings would approach \$233 million.

James E. Eason
January 8, 1988
Page 2

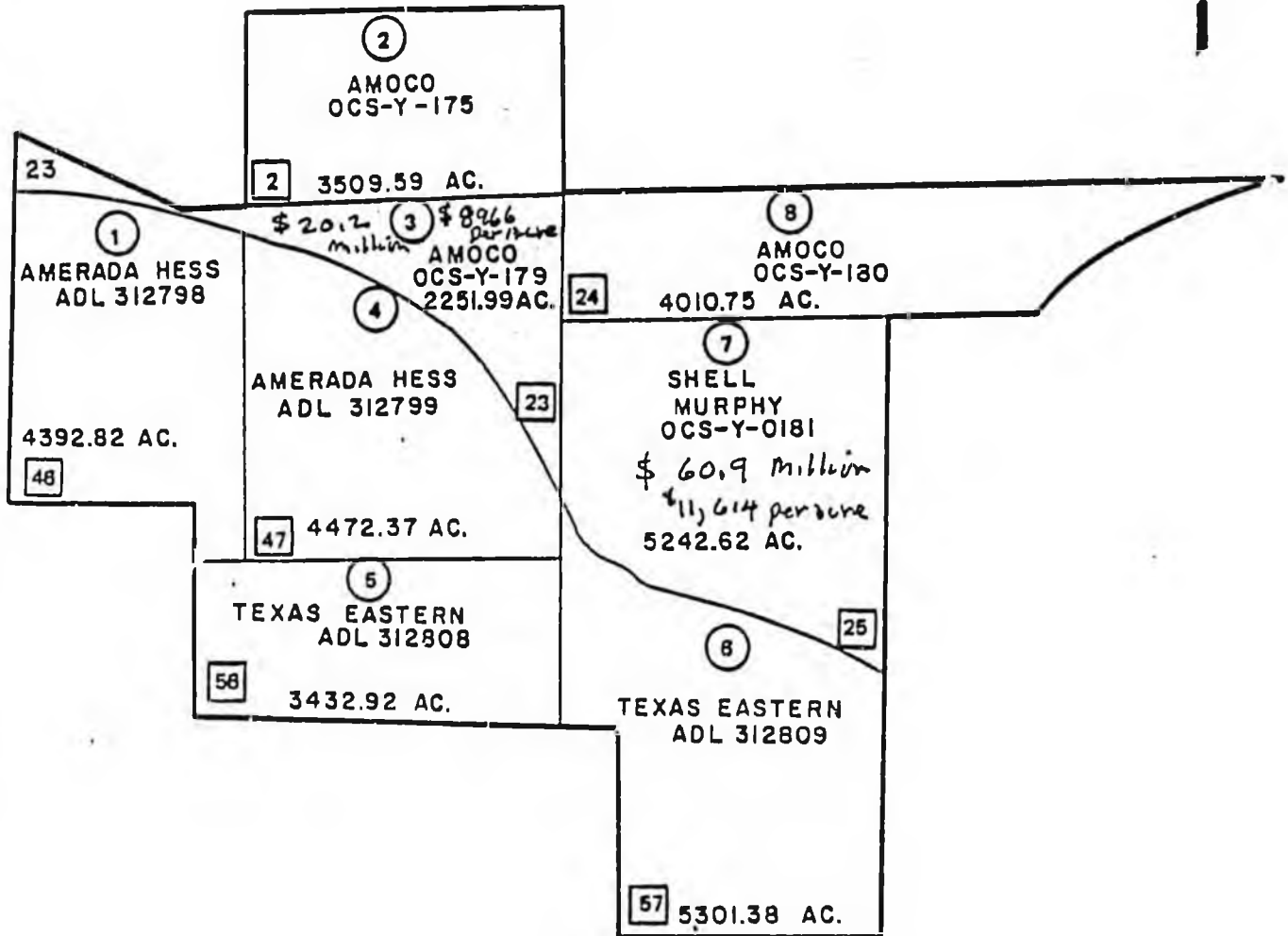
Thus, to this point in time the major sacrifice has been by the state in foregone bonuses and Permanent Fund contributions, including potential interest earnings. The Permanent Fund share of the estimated foregone bonuses would be \$78.5 million. This amount would have accrued to \$219.53 million by January of this year.

The current proposal appears to extend the state's sacrifice to a "foregone" conclusion.

Attachment

1269E

State Leases Bonus Bid = \$875.00 per acre
 Federal Leases Bonus Bid = \$10,808 per Acre
 Fed Royalty 16 $\frac{2}{3}$ % + Sliding Scale Royalty to
 Max of 65 %



LEGEND
 UNIT OUTLINE ———
 LEASE BOUNDARY ———
 UNIT TRACT NO. (1)
 LEASE SALE BF (2)
 TRACT NO. (2)

NO SCALE

**EXHIBIT B
 SEAL UNIT
 BEAUFORT SEA, ALASKA**

December 3, 1987

MEMORANDUM

TO: Jan

SUBJECT: State Chamber Speech

Making Alaska more competitive in the truly international market for limited oil industry investment capital will increase economic activity, increase employment both in primary and secondary industries, and increase long term income to the state at a time when Alaska needs it the most.

Currently the Division of Oil and Gas is reviewing incentive legislation from several other states and Canadian provinces, and they have indicated that specific recommendations will be made to Commissioner Brady and the Governor in mid-December.

My own review of much of the same legislation has concluded that there are several incentives which could be particularly effective in Alaska. The general scope of these different types of incentives are summarized in the handout.

When we talk about incentives we need to consider the 3 R's: RESOURCE, RESERVE, & ROYALTY. You start with a resource in the ground. It doesn't become a reserve until someone drills and discovers it. The state then gets the royalty after production begins. What we are trying to accomplish with incentives is provide the impetus to change reserves into royalties and economic development for those situations where it wouldn't happen under current economic conditions.

(HERE IS THE TEXT OF THE HANDOUT. EACH SECTION IS FOLLOWED BY ADDITIONAL INFORMATION FOR YOU TO PRESENT)

SEVERANCE TAX EXEMPTIONS AND ROYALTY HOLIDAYS: Encourage development of new reserves by offering limited time severance tax exemptions and royalty holidays for new wells drilled during a specified time period. Such a program could be designed so that the exemption would be reduced if oil prices rise above a predetermined level.

(This would be similar to:

1. Alberta's Crude Oil Royalty Holiday Program which allowed for the greater of a 12-month royalty-free period for each eligible well to a maximum of \$1 million per well, or a royalty exemption determined by applying a formula to the specific characteristics of the well.

2. Saskatchewan's Royalty/Tax holiday. During the period January 1, 1987 to June 30, 1988, eligible wells and projects will receive a three year royalty or tax holiday. During the period July 1, 1988 to June 30, 1989 eligible wells and projects will receive a two year royalty or tax holiday.

3. Louisiana's Severance Tax Exemption Plan provided that wells drilled between July 15, 1986 and July 15, 1987 will pay no severance taxes through 1990, and provided an incentive to drill marginal wells on known reservoirs. Louisiana's Economic Acceleration Plan provides no tax on development through 1989 for discoveries after July, 1986 and has no production limits on its exemption which provides a significant incentive to explore for new prospects.

4. These two programs in Louisiana were enacted in 1986 to provide a significant incentive to drill new wells. It obviously worked since in 1987 the state of Mississippi felt compelled to enact very similar legislation in an effort to compete with Louisiana for limited drilling activity.

DISCOVERY ROYALTY: Could be structured much the same as the state's previous discovery royalty statutes, which were repealed by the Legislature in 1969. Would allow a limited time reduction in the royalty rate for a producer who discovers and produces oil and gas from a state lease within a specific timeframe.

(The Discovery Royalty statute was repealed by the Legislature following the discovery of the reserves at Prudhoe Bay. Under a discovery royalty a lessee would be entitled to withhold a discovery royalty award, say 60% for example, from the oil and gas royalty payable to the state for that lease for a specified period of time, such as 10 years.)

EXPLORATION INCENTIVE CREDITS: Currently AS 38.05.180(i) allows the Commissioner of the Department of Natural Resources to utilize exploration incentive credits. Expanded use of exploration credit incentives to include additional qualifying leases could be extremely effective in stimulating new drilling activity. This could be accomplished under existing state law.

(Two points:

1. On April 1, 1987 Alberta instituted an Exploratory Drilling Assistance Program. This program allows 50% of the cost of an exploratory well to receive credits. These credits can be used to reduce royalty payments, or they can be transferred to another operator.
2. As a very encouraging first step, the State of Alaska's Division of Oil and Gas has announced that it intends to make credits available for those leases which will be offered in Kuparuk Uplands Sale 54, which is scheduled for this January. According to the Division, this will be the first time that exploration credits have been offered without linking the credits to net profit share lease terms.

ENHANCED OIL RECOVERY: Enhanced recovery projects are more capital and labor intensive than primary operations, and the multiplier effect on overall economic activity is much greater. Enhanced recovery projects could be exempted from severance taxes for limited time periods. In addition, the current gas plant investment tax credit could be expanded to a broader based investment tax credit system that could enhance the attractiveness of large projects such as enhanced oil recovery.

(Some additional points:

1. Particular to Alaskan conditions, enhanced recovery incentives should be targeted at development of reserves which otherwise wouldn't be developed, either secondary production from an existing field or initial production from a field which is uneconomic under current conditions.
2. The average recovery efficiency for oil production in the United States is 32.1%, which means that over two thirds of the oil in place will remain in the ground.
3. The federal government's Enhanced Recovery Act of 1979 provided an economic incentive to undertake enhanced recovery programs. During the four plus years this program was effective, a total of 425 enhanced recovery projects were initiated in the United States.
4. Earlier this year Oklahoma enacted legislation which exempts all EOR production from severance taxes until either the payback is completed or three years have passed.
5. Incentives such as these could be designed to improve the economics of the largest undeveloped oil accumulations in Alaska, West Sak and Ugnu Sands.

NEW TAX COURT: Currently there are roughly \$1.5 billion in outstanding disputed tax assessments according to the

Department of Revenue. A report released earlier this year by Common Sense exposed many of the inefficiencies in the current system which have been in large part a cause of this problem.

The current system for appealing disputed tax assessments is perceived by many as being unfair to taxpayers within the state, which has created a negative impact on Alaska's business climate.

The tax court legislation which has been drafted establishes a new division within the superior court system, and allows the taxpayer the option of appealing directly to that court rather than going through what is perceived as an unnecessarily long and unfair process within the Department of Revenue.

The tax court legislation makes the appeal process more uniform with the federal appeal process, and should significantly reduce the inequities in the way tax disputes are currently resolved.

THE OTHER TWO HANDOUTS ARE:

1. Oil Price Watch Indicators.
2. RDC Economic Development Legislation

ATTACHMENT I

LOUISIANA SEVERANCE TAX EXEMPTION PROGRAM (STEP) AND LOUISIANA ECONOMIC ACCELERATION PROGRAM (LEAP)

STEP Well - Any oil well that is spudded and completed during the time period from July 15, 1986 through July 15, 1988; and is certified by the Louisiana Office of Conservation, will be exempt from state severance tax on the first 50 barrels of oil produced each day. Each qualified STEP Well is limited to a maximum exemption of 10,000 barrels per annual period based on the date of first production. This exemption will last through July 15, 1990, but does not apply during any month in which the value of the oil produced exceeds \$21.00 per barrel. No severance tax exemption will apply to production obtained as a result of a well being deepened, side tracted, or recompleted after July 15, 1988. It is likely, however, that attempts to restore production from an oil well drilled within the STEP period by reworking operations will qualify for continued STEP treatment.

In order to certify a well as a STEP Well, a producer must provide the following to the Louisiana Office of Conservation:

1. Evidence supporting the date the well was spudded (must be on or after July 15, 1986);
2. Evidence supporting the date drilling was completed (must be on or before July 15, 1988):
3. Production information establishing the wells capacity to produce;
4. Documentation that the well is classified as an oil well;
5. Evidence supporting the price being received for the oil produced; and
6. Certification that "to the maximum extent possible," at least 10% of the service contracts related to the well drilling have been made available to minority-owned businesses and at least 5% of the service contracts have been made available to women-owned businesses.

In order for the producer to claim the exemption on a certified well, Form O-4 must be filed with the Department of Revenue and Taxation each month indicating the wells activity during the previous month. This form must be filed by the last day of the month following production and must be accompanied by a copy of the Producers report and the Office of Conservations certification of qualified wells. Even though the exemption will not apply during any month in which the value of the oil exceeds \$21.00 a barrel, a report must still be filed to report the total production from the well and to reflect that none of the production for that month is eligible. If for any month this procedure is not followed, the exemption for that month will be lost.

LEAP Well - Any oil or natural gas discovery well that is drilled, completed, and produced as a "wildcat well" during the time period from July 1, 1986 through January 1, 1990; and is certified by the Louisiana Office of Conservation, will be exempt from state severance tax until January 1, 1990, or until the posted price of West Texas Intermediate Crude equals or exceeds

ATTACHMENT I

LOUISIANA SEVERANCE TAX EXEMPTION PROGRAM (STEP) AND LOUISIANA ECONOMIC ACCELERATION PROGRAM (LEAP)

\$29.50 per barrel, whichever occurs first. Also exempt would be a subsequent "developmental well" in the same field during the same time period referenced above.

A wildcat well is drilled in search of oil or natural gas accumulations located in a non-productive area, away from a known productive geological structure. Upon successful completion, the wildcat well is then recognized as a discovery well. A "developmental well" must be drilled and completed to a pool previously discovered by a wildcat well.

The exemption does not include a well drilled in a contiguous fault segment of a sand that was either producing or capable of producing prior to July 1, 1986; or to a well subsequently recompleted in a sand previously penetrated from a well that was drilled, completed, and/or produced prior to July 1, 1986.

The certification process for a LEAP Well includes a public hearing where an application is filed by the producer. The application must include:

1. Identification of the potential production zone, its depth, location, geology, and engineering data. Such data must show that the production reservoir is geologically separated (structurally, and/or stratigraphically) from the nearest reservoir that has produced, or is known to have been capable of producing hydrocarbons.
2. Geological and engineering evidence - including electric logs, structure maps, isopachs, bottom hole pressure and production history - supporting classification as a geologically separated reservoir.
3. Certification that, to the maximum extent possible, Louisiana residents were employed during the exploration and production activities undertaken in connection with the well.
4. Certification that, to the maximum extent possible, at least 10% of the operator's service contracts related to the well were made available to minority owned businesses.

ATTACHMENT II

MISSISSIPPI SEVERANCE TAX INCENTIVES

Oil: Any well for which drilling is commenced after March 15, 1987, and before July 1, 1988, and for which qualification has been obtained from the Mississippi State Tax Commission, shall be exempt from the 6% severance tax to the following extent: The exemption shall apply to the first 50 barrels of oil removed from the ground each day for wells drilled to a depth of 12,000 feet or less and shall apply to the first 100 barrels of oil removed from the ground each day for wells drilled to a depth greater than 12,000 feet below the surface. This exemption will last until June 30, 1990, but does not apply during any month that the average value of oil, as determined by the State Tax Commission, exceeds \$25.00 per barrel.

Enhanced Recovery Production: Oil production from an enhanced recovery project where carbon dioxide (CO₂) is used will be taxed at a reduced rate of 3% provided that such CO₂ is transported by pipeline to the oil well site. Gas, including CO₂, used in an enhanced oil recovery method is exempt from severance tax.

Natural Gas and Condensate: Any well for which drilling is commenced after March 15, 1987, and before July 1, 1988, and for which qualification has been obtained from the Mississippi State Tax Commission, shall be exempt from the 6% severance tax for a period of two years beginning on the date of first sale of production from such well.

ATTACHMENT III

MONTANA TAX INCENTIVES

Severance Tax Exemptions

Oil:

New Production: New production is exempt for 2 years following notification made to the Department of Revenue after March 31, 1987 and before July 1, 1991. New production is defined as coming from any well that has not produced during the 5 years immediately preceding the first month of qualified new production; and on which notification was made after March 31, 1987. The exemption terminates when it is certified that the price of WTI crude oil has reached \$25 per barrel.

Stripper: The first 5 barrels of average daily production from a stripper are exempt from severance tax. Production after the first 5 barrels is taxed at a reduced rate of 3% for production from April 1, 1987 through March 31, 1989. A stripper is defined as any well that produces less than 10 barrels per day determined by dividing the amount of production from a lease or unitized area for the year prior to the current calendar year by the number of producing wells and by dividing the resulting quotient by 365. The exemption and the reduced rate will terminate when it is certified that the price of WTI has reached \$30 per barrel.

The tax on other petroleum and mineral or crude oil production continues to be taxed at 5%, except production from a tertiary recovery project which is taxed at 2.5%.

Gas:

Low Production: The first 30,000 cubic feet of average daily production of natural gas from a well that has produced 60,000 cubic feet or less of natural gas per day for the calendar year prior to the current tax year is exempt from tax, and the remainder of natural gas produced from such well is taxed at 1.59%. The prior year production calculation is determined by dividing the prior calendar year production by the number of producing wells and by dividing the resulting quotient by 365.

All other natural gas is taxed at 2.65% of total gross value.

Net Proceeds Exemptions

New Production: New production of natural gas, petroleum, or other crude or mineral oil is exempt from the oil and gas net proceeds tax for the first 12 months of production. New production is defined as the production of natural gas, petroleum, or other crude or mineral oil from any well:

ATTACHMENT III

MONTANA TAX INCENTIVES

New Production: (Cont'd.)

- that has not produced during the 5 years immediately preceding the first month of qualified new production; and
- on which proper notification has been given.
- effective after 1986 per s.b. 66.

Qualified Gas: Natural gas produced from a well 5,000 feet deep or deeper, for which drilling was completed after December 31, 1976 but before April 1, 1987 is exempt from 1/2 of net proceeds tax for 3 years if the gas produced from the well is:

- placed into a natural gas distribution system for delivery to consumers after diligent completion of the well; and
- distributed by a natural gas distribution system serving only natural gas consumers a majority of which are within Montana or at least 10,000 natural gas consumers within Montana.

The 3 year exemption period begins when natural gas from a qualifying well is first placed into a natural gas distribution system.

ATTACHMENT IV

NORTH DAKOTA OIL EXTRACTION TAX INCENTIVES

New Well: Any well that is drilled and completed after April 27, 1987 and is qualified by the North Dakota Industrial Commission, will be exempt from the 6.5% OET for a period of 15 months from the well completion date. This exemption applies both to new wells spudded and to existing wells that are deepened provided that each well is completed to a separate and distinct reservoir. After the 15 month period, new wells will be taxed at a reduced rate of 4%.

Qualified Waterflood: To qualify for the reduced OET rate of 4%, a well must be certified by the North Dakota Industrial Commission and be located on a secondary recovery project which meets the following specifications set forth by the state:

1. It must have been unitized after April 27, 1987;
2. It must employ waterflooding; and
3. It must have achieved an average production level of at least 25% above the normal recovery level for a period of six consecutive months.

Qualified Tertiary: To be eligible for the reduced OET rate of 4%, a well must be certified by the North Dakota Industrial Commission, must be located on a qualifying tertiary recovery project, and must have achieved a production level of at least 15% above the normal recovery level for a period of no less than one month.

Qualified Stripper: In order to qualify for the Stripper Well Exemption, a property must be certified by the North Dakota Industrial Commission and average daily production (based on calendar days) for any consecutive 12-month period after December 31, 1972:

1. Cannot exceed ten barrels per day for wells a depth of 6,000 feet or less; or
2. Cannot exceed fifteen barrels per day for wells a depth of more than 6,000 feet but not more than 10,000 feet; or
3. Cannot exceed twenty barrels per day for wells a depth of more than 10,000 feet.

The Stripper Well incentive will continue indefinitely. The other incentives, however, will continue until the average price of West Texas Intermediate Cushing Oil is thirty-three dollars or more between June 1st and October 31st of any given year. At such time, the 15 month exemption will be eliminated effective November 1st. All qualified new wells, waterflood wells, and tertiary wells will be taxed at 4% for the remaining two months of that year, and effective January 1st of the following year will be taxed at 6.5%.

ATTACHMENT V

OKLAHOMA SEVERANCE TAX INCENTIVES

Enhanced Recovery: Any incremental production which results from an enhanced recovery project shall be exempt from gross production tax from the project beginning date until project payback is achieved for new enhanced recovery projects or until project payback is achieved but not to exceed a period of 36 months for tertiary enhanced recovery projects existing on the effective date of this act. (Effective July 1, 1988.)

ATTACHMENT VI

WYOMING SEVERANCE TAX INCENTIVE

Wildcat Well: Oil and gas produced from a wildcat well drilled and completed after January 1, 1987 and on or before December 31, 1989, is exempt from severance taxes for 4 years commencing the date of first production from the well. A wildcat well is any well so designated by the Wyoming Oil and Gas Conservation Commission. Such wildcat wells must be well outside of known fields or new well which are determined by the commission to have discovered oil or gas in a pool not previously proven productive. (Effective 3-17-87.)

LAWS AFFECTING STATE SEVERANCE TAX
ENACTED 1987

ALASKA:

HB 124

WOULD INCREASE FROM .125¢ TO .4¢ PER BARREL THE "OIL AND GAS" CONSERVATION TAX, AND EXTEND THE TAX TO COVER EACH 50 MCF UNIT OF GAS. SIGNED INTO LAW 6-12-87.

KANSAS:

SB 1

PROVIDES SEVERANCE TAX RELIEF BASED ON THE PRICE OF OIL (AS OIL PRICES GO UP OR DOWN, EXEMPTIONS FROM THE SEVERANCE TAX WOULD RISE OR FALL). SIGNED INTO LAW.

MISSISSIPPI:

SB 2111

PROVIDES FOR AN EXEMPTION FROM OIL AND GAS SEVERANCE TAX ON CERTAIN PRODUCTION FROM NEW WELLS. SIGNED INTO LAW.

MONTANA:

HB 776

EXEMPTS STRIPPER WELLS AND, FOR THE FIRST 2 YEARS OF PRODUCTION, ALL OTHER WELLS PRODUCING PETROLEUM, NATURAL GAS, OR OTHER MINERAL OR CRUDE OIL FROM SEVERANCE TAXES AND LOWERS THE SEVERANCE TAX RATE TO 3 PERCENT FOR CERTAIN STRIPPER WELLS. SIGNED INTO LAW.

SB 066

REDEFINES "NEW PRODUCTION" OF NATURAL GAS, PETROLEUM OR OTHER CRUDE OR MINERAL OIL FOR PURPOSES OF DETERMINING THE NET PROCEEDS TAX. SIGNED INTO LAW.

SB 383

PROVIDES A PERMANENT HOLIDAY FROM THE NET PROCEEDS TAX ON THE FIRST 12 MONTHS OF PRODUCTION FROM NEW OIL OR GAS WELLS. SIGNED INTO LAW.

NEW MEXICO:

CS/HB 360

REDUCES NATURAL GAS SEVERANCE TAX FROM CURRENT 16.3 CENTS AN MCF TO 14 CENTS DURING NEXT FISCAL YEAR (STARTING JULY 1); 12 CENTS FOLLOWING YEAR; 10 CENTS THE YEAR AFTER THAT, AND 3.75% OF VALUE AFTER THE END OF THAT FISCAL YEAR (JUNE 30, 1990). ALSO, 3.75% ON PRODUCTION FROM WELLS WHICH BEGIN PRODUCING GAS AFTER MAY 1, 1987. SIGNED INTO LAW.

AMERADA HESS CORPORATION
INTEROFFICE CORRESPONDENCE

JUNE 15, 1987

TO: P. A. DYSERT
FROM: MARILYN O. ADAMSON
SUBJECT: STATE SEVERANCE TAXES - 1987

AT THE REQUEST OF M. B. BIANCHI, I AM FORWARDING THE ATTACHED INFORMATION ON LAWS AFFECTING SEVERANCE TAXES WHICH WERE PASSED BY STATE LEGISLATURES DURING THE 1987 LEGISLATIVE SESSION. WE DO NOT RECEIVE INFORMATION ON ALL STATES, AND HAVE NOT RECEIVED OFFICIAL FINAL REPORTS FROM SEVERAL; HOWEVER, THIS SHOULD BE REASONABLY COMPLETE FOR ALL LEGISLATURES EXCEPT LOUISIANA, WHICH IS NOT YET ADJOURNED. PLEASE ADVISE IF YOU WISH FURTHER DEAL OF ANY OF THESE ENACTMENTS, AS THE LEGAL DEPARTMENT HAS FULL COPIES OF MOST OF THESE BILLS IN ITS FILES.



MARILYN O. ADAMSON

MOA:SGB

ATTACHMENT

CC: M. B. BIANCHI
D. F. MCCARTHY
D. G. STEVENSON
W. R. TENNANT
A. A. VANMIEGHEM

**LAWS AFFECTING STATE SEVERANCE TAX
ENACTED 1987**

ALASKA:

HB 124

WOULD INCREASE FROM .125¢ TO .4¢ PER BARREL THE "OIL AND GAS" CONSERVATION TAX, AND EXTEND THE TAX TO COVER EACH 50 MCF UNIT OF GAS. SIGNED INTO LAW 6-12-87.

KANSAS:

SB 1

PROVIDES SEVERANCE TAX RELIEF BASED ON THE PRICE OF OIL (AS OIL PRICES GO UP OR DOWN, EXEMPTIONS FROM THE SEVERANCE TAX WOULD RISE OR FALL). SIGNED INTO LAW.

MISSISSIPPI:

SB 2111

PROVIDES FOR AN EXEMPTION FROM OIL AND GAS SEVERANCE TAX ON CERTAIN PRODUCTION FROM NEW WELLS. SIGNED INTO LAW.

MONTANA:

HB 776

EXEMPTS STRIPPER WELLS AND, FOR THE FIRST 2 YEARS OF PRODUCTION, ALL OTHER WELLS PRODUCING PETROLEUM, NATURAL GAS, OR OTHER MINERAL OR CRUDE OIL FROM SEVERANCE TAXES AND LOWERS THE SEVERANCE TAX RATE TO 3 PERCENT FOR CERTAIN STRIPPER WELLS. SIGNED INTO LAW.

SB 066

REDEFINES "NEW PRODUCTION" OF NATURAL GAS, PETROLEUM OR OTHER CRUDE OR MINERAL OIL FOR PURPOSES OF DETERMINING THE NET PROCEEDS TAX. SIGNED INTO LAW.

SB 383

PROVIDES A PERMANENT HOLIDAY FROM THE NET PROCEEDS TAX ON THE FIRST 12 MONTHS OF PRODUCTION FROM NEW OIL OR GAS WELLS. SIGNED INTO LAW.

NEW MEXICO:

CS/HB 360

REDUCES NATURAL GAS SEVERANCE TAX FROM CURRENT 16.3 CENTS AN MCF TO 14 CENTS DURING NEXT FISCAL YEAR (STARTING JULY 1); 12 CENTS FOLLOWING YEAR; 10 CENTS THE YEAR AFTER THAT, AND 3.75% OF VALUE AFTER THE END OF THAT FISCAL YEAR (JUNE 30, 1990). ALSO, 3.75% ON PRODUCTION FROM WELLS WHICH BEGIN PRODUCING GAS AFTER MAY 1, 1987. SIGNED INTO LAW.

NORTH DAKOTA:

SB 2078

PROVIDES A TWO-YEAR EXEMPTION FROM THE 6.5% EXTRACTION TAX FOR ANY WELL STARTED AFTER MARCH 31, 1987 AND COMPLETED PRIOR TO JULY 1, 1989. SIGNED INTO LAW. } M. = 1/21

SB 2079

PROVIDES FOR A STRIPPER WELL DEFINITION BASED ON YIELD AND WELL DEPTH; PROVIDES FOR A 15-MONTH MORATORIUM FROM THE 6.5% EXTRACTION TAX ON ALL NEW WELLS; PROVIDES A 2.5% REDUCTION IN THE 6.5% EXTRACTION TAX FOR ALL NEW OIL AFTER THE EXPIRATION OF THE MORATORIUM PERIOD, AS WELL AS FOR NEW QUALIFYING SECONDARY AND TERTIARY RECOVERY PROJECTS; AND TIE ALL OF THE EXTRACTION TAX REDUCTIONS EXCEPT THE STRIPPER WELL REDEFINITION TO A TRIGGER PRICE OF \$33 WEST TEXAS INTERMEDIATE (WTI) CRUDE OIL. WHEN WTI CRUDE OIL IS PRICED AT \$33 OR MORE FOR THE BASE PERIOD, THE FULL 6.5% EXTRACTION TAX WILL AGAIN APPLY. SIGNED INTO LAW.

OKLAHOMA:

HB 1139

EXEMPTS FROM THE GROSS PRODUCTION TAX THE OIL PRODUCTION FROM ENHANCED RECOVERY PROJECTS UNTIL PROJECT PAYBACK IS ACHIEVED OR FOR 36 MONTHS FOR TERTIARY PROJECTS. SIGNED INTO LAW.

WYOMING:

HB 55

PROVIDES FOR A FOUR-YEAR, 4% SEVERANCE TAX EXEMPTION FOR ANY OIL OR GAS WELL DRILLED IN 1987 AND 1988. SIGNED INTO LAW.

HB 275

ALLOWS SEVERANCE TAXES ON CARBON DIOXIDE TO BE A DIRECT CREDIT AGAINST SEVERANCE TAXES ON OIL PRODUCED BY INJECTION OF THE GAS. SIGNED INTO LAW.

HB 347

EXEMPTS FROM TAXATION SPECIFIED FLARED OR VENTED GAS, REINJECTED GAS AND GAS CONSUMED ON LEASE WITHOUT SALE. SIGNED INTO LAW.

NORTH DAKOTA:

SB 2079

PROVIDES FOR A STRIPPER WELL DEFINITION BASED ON YIELD AND WELL DEPTH; PROVIDES FOR A 15-MONTH MORATORIUM FROM THE 6.5% EXTRACTION TAX ON ALL NEW WELLS; PROVIDES A 2.5% REDUCTION IN THE 6.5% EXTRACTION TAX FOR ALL NEW OIL AFTER THE EXPIRATION OF THE MORATORIUM PERIOD, AS WELL AS FOR NEW QUALIFYING SECONDARY AND TERTIARY RECOVERY PROJECTS; AND TIE ALL OF THE EXTRACTION TAX REDUCTIONS EXCEPT THE STRIPPER WELL REDEFINITION TO A TRIGGER PRICE OF \$33 WEST TEXAS INTERMEDIATE (WTI) CRUDE OIL. WHEN WTI CRUDE OIL IS PRICED AT \$33 OR MORE FOR THE BASE PERIOD, THE FULL 6.5% EXTRACTION TAX WILL AGAIN APPLY. SIGNED INTO LAW.

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WYOMING:

HB 55

PROVIDES FOR A FOUR-YEAR, 4% SEVERANCE TAX EXEMPTION FOR ANY OIL OR GAS WELL DRILLED IN 1987 AND 1988. SIGNED INTO LAW.

HB 275

ALLOWS SEVERANCE TAXES ON CARBON DIOXIDE TO BE A DIRECT CREDIT AGAINST SEVERANCE TAXES ON OIL PRODUCED BY INJECTION OF THE GAS. SIGNED INTO LAW.

HB 347

EXEMPTS FROM TAXATION SPECIFIED FLARED OR VENTED GAS, REINJECTED GAS AND GAS CONSUMED ON LEASE WITHOUT SALE. SIGNED INTO LAW.

State of Alaska
MEMORANDUM

Office of the Governor

Division of Policy

P.O. Box AM, Juneau, AK, 99811
Tel. 465-3568 / Mail Stop 0161

TO: Rep. Drew Pearce

DATE: 19 March 1987

FROM: Gregg Erickson
Senior Economist

SUBJECT: Shares of Alaska Oil Revenue.

I have enclosed OMB's most recent (April 11, 1986) analysis of the shares of net revenue from oil production and transportation in Alaska during the FY 82-85 period. Oil industry Alaska profits over this 4-year period (net of capital charges, costs, royalties and taxes) totaled \$22,103 million.

The profits earned in Alaska can be compared with the \$6 billion in oil industry invested in Alaska over the same period. Testimony of Harold Heinze, House Finance transcript, April 12, 1985, p. 130.

I have also provided copies of our correspondence with Exxon regarding the "shares" analysis.

cc: Rep. Cotten
Mary Halloran

file
oil Revenue

STATE, FEDERAL AND INDUSTRY SHARES OF ALASKA OIL
RESOURCE INCOME: FISCAL 1982-1985
(millions of dollars except as noted)

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Fiscal	Total	State	Sever.	Total	Total	Total	Total	Windfall
year	Revenue	Royalty	Conser.	Prop.	Oper.	Deprec.	Acquis.	Profits
			tax	tax	Costs		Costs	Tax
1982	\$16,456	\$1,553	\$1,581	\$276	\$940	\$602	\$1	\$2,018
1983	\$15,470	\$1,448	\$1,494	\$307	\$1,101	\$780	\$1	\$1,018
1984	\$14,955	\$1,409	\$1,393	\$358	\$1,259	\$998	\$1	\$412
1985	\$15,136	\$1,390	\$1,389	\$397	\$1,449	\$1,093	\$1	\$70

	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]
Fiscal	Uncap.	Explore.	Admin.	Other	Total	State	Corp.	Federal
Year	Interest	Costs	Costs	Deducs.	Deducs.	Taxable	Petrol	Taxable
	Expense					Net	Income	Income
						Income	Tax	
1982	\$721	\$191	\$236	\$149	\$8,268	\$8,188	\$669	\$7,519
1983	\$676	\$204	\$252	\$142	\$7,423	\$8,047	\$236	\$7,811
1984	\$614	\$219	\$265	\$136	\$7,064	\$7,891	\$265	\$7,626
1985	\$566	\$234	\$278	\$130	\$6,997	\$8,139	\$169	\$7,970

	[17]	[18]	[19]	[20]	[21]	[22]	[23]
Fiscal	Federal	Oil	Total	Total	---Share of Oil Income---		
Year	Corp.	Industry	Federal	State	State	Federal	Industry
	Income	Profits	Tax	Tax &			
	Tax		Royalty				
1982	\$2,098	\$5,421	\$4,116	\$4,079	30%	30%	40%
1983	\$2,140	\$5,671	\$3,158	\$3,485	28%	26%	46%
1984	\$2,242	\$5,384	\$2,654	\$3,425	30%	23%	47%
1985	\$2,343	\$5,627	\$2,413	\$3,345	29%	21%	49%

SOURCES AND FORMULAS --

Column [1]: Vincent Wright, chief of research, to Mary Nordale, Commissioner of Revenue, Memorandum of October 31, 1985, Table 3.

Columns [2] & [3]: January 1986 DOR Revenue Sources, p. 39.

Columns [4] to [12]: Vincent Wright, loc. cit.

Column [13]: sum of columns [2] through [12]

Column [14]: column [1] - column [13]

Column [15]: Revenue Sources, p. 39.

Column [16]: column [14] - column [15].

Column [17]: column [16] * (production-weighted average tax rate - 1982 = .279; 1983 = .274; 1984 = .294; 1985 = .294). Company effective rates for '82-84 from R. McIntire and R. Folen, "Corporate Income Taxes in the Reagan Years," Oct. 1984, pp. 32-36; '85 estimated by OMB.

Column [18]: column [16] - column [17].

Column [19]: column [8] + column [17].

Column [20]: sum of columns [2], [3], [4], and [15].

Column [21]: (column [18])/(sum of columns [18], [19], and [20]).

Column [22]: (column [19])/(sum of columns [18], [19], and [20]).

Column [23]: (column [20])/(sum of columns [18], [19], and [20]).

Joseph M. Wilson, Esq.
Louis R. Veerman, Esq.
Guess & Rudd
510 L Street, Suite 700
Anchorage, Alaska 99501
(907) 276-5121

Attorneys for Plaintiff

IN THE SUPERIOR COURT FOR THE STATE OF ALASKA
THIRD JUDICIAL DISTRICT AT ANCHORAGE

STANDARD ALASKA PRODUCTION)
COMPANY,)
)
Plaintiff,)
)
v.)
)
STATE OF ALASKA, DEPARTMENT)
OF REVENUE,)
)
Defendant.)
_____)

Case No. 3A11-87-_____ Civ.

COMPLAINT FOR DECLARATORY JUDGMENT

Plaintiff, Standard Alaska Production Company (the "Taxpayer"), by and through its counsel, Guess & Rudd, brings this action for declaratory relief against the State of Alaska, Department of Revenue (the "Department"), and alleges as follows:

INTRODUCTION

1. This is an action for a judgment declaring that the Department lacks authority to assess an amount of tax greater than the amount assessed within the applicable statute limiting the Department's authority to make assessments. Accordingly, certain tax assessments the Department has made against the Taxpayer are invalid because they (i) are barred by the statute limiting the Department's assessment powers, (ii) are inconsistent with the Department's regulations, (iii) lack statutory authority, and (iv) amount to a denial of due process of law.

JURISDICTION

2. This action presents an actual controversy over which this Court has jurisdiction pursuant to AS 22.10.020(b).

3. This action also presents a challenge by an interested party to the validity of a regulation of an administrative agency over which this Court has jurisdiction pursuant to AS 44.62.300.

4. The issues presented are purely legal in nature and do not involve the application of agency expertise.

PARTIES

5. The Taxpayer is a corporation organized and existing under the laws of the State of Delaware and is qualified to do business in the State of Alaska, having paid its corporate taxes and filed its biennial report last due. The Taxpayer's business within the State consists primarily of oil and gas exploration, development and production operations.

6. The Department is a department within the executive branch of the State of Alaska, established pursuant to Article III, Section 22 of the Constitution of the State of Alaska.

GENERAL ALLEGATIONS

7. The Taxpayer has been and continues to be required to file returns and pay various taxes imposed by the State of Alaska pursuant to Title 43, Alaska Statutes.

8. The Department regularly audits the tax returns of taxpayers engaged in the oil and gas business in Alaska.

9. The Department issues assessments for additional tax when it appears upon audit that a return filed under Title 43 has understated the amount of tax due.

10. AS 43.05.260(a) provides for a three-year limitation period on assessments.

11. The Department was required to make an initial determination of income under AS 43.21 on or before August 15th of the year following the taxable year (the "Original Assessment"), and was authorized to amend the Original Assessment or any subsequent amended assessments up to three years from the date of the Original Assessment. AS 43.21.050, 15 AAC 21.700(e).

12. Under 15 AAC 21.810(1) the Department may amend an assessment "no later than" three years from the date the tax return was due or filed, whichever is later.

13. The Taxpayer timely filed its oil and gas corporate income tax return for the 1978 taxable year (the "1978 Return") on June 15, 1979.

14. The time period for amending assessments related to the Taxpayer's 1978 Return expired under AS 43.05.260(a) either on June 15, 1982, as provided in 15 AAC 21.810(1), or on August 15, 1982, as provided in 15 AAC 21.700(e).

15. The Department audited the 1978 Return and, on August 15, 1979, issued an Original Assessment. On December

31, 1981, the Department timely issued an "Amended Notice of Assessment" (the "First Amended Assessment") for the Taxpayer's 1978 taxable year.

16. On February 24 and 28, 1984, more than four and one-half years after the Taxpayer filed its 1978 Return and received the Original Assessment, the Taxpayer received from the Department undated documents captioned "Amendments to Audit Narrative" and accompanying schedules (the "Second Amended Assessment"), which purported to increase substantially the amount set forth in the First Amended Assessment. The Second Amended Assessment was untimely because it was not issued by either June 15 or August 15, 1982.

17. In February 1985, more than five and one-half years after the Taxpayer filed its 1978 Return and received the Original Assessment, the Taxpayer received a document dated February 4, 1985, captioned "Amended Notice and Demand for Payment" (the "Third Amended Assessment"), which again purported to assess, for the Taxpayer's 1978 taxable year, an amount of tax in excess of the amount set forth in the First Amended Assessment. The Third Amended Assessment was untimely because it was not issued by either June 15 or August 15, 1982.

18. The Taxpayer timely protested the First, Second, and Third Amended Assessments, and ultimately withdrew its protest to the Second Amended Assessment, as the Department has agreed that the Third Amended Assessment superceded and replaced the Second Amended Assessment.

19. In issuing the Second and Third Amended Assessments, the Department has interpreted AS 43.05.260 to permit the assessment of additional taxes after the three-year limitation period, but only if the Taxpayer exercises its rights to obtain administrative and judicial review of an assessment by filing a protest.

20. The Department's interpretation of AS 43.05.260 constitutes a "regulation" within the meaning of AS 44.62.300.

21. The Department's issuance of the Second and Third Amended Assessments has created uncertainty as to the Taxpayer's legal rights and duties under AS 43.05.260 for its 1978 taxable year. This uncertainty would be resolved by issuance of the declaration sought in this Complaint.

22. The Department's issuance of the Second and Third Amended Assessments has subjected the Taxpayer to a threat of injury, in that the Department is seeking to hold the Taxpayer

liable for additional income taxes with respect to its 1978 taxable year, and may seek to hold the Taxpayer liable for still more additional taxes for that year, without any effective time limit or closure of that year, unless this Court declares the Department's interpretation of AS 43.05.260 to be invalid and the Second and Third Amended Assessments void.

23. Even if the Taxpayer ultimately prevails on the substantive tax issues raised in the Second and Third Amended Assessments, the Taxpayer will have been damaged by virtue of having been forced: (i) to divert legal, accounting and operating personnel from their normal duties to prepare and review the exhaustive factual and legal analyses necessary to adequately evaluate and prepare the Taxpayer's defense with respect to the substantive tax issues raised, and (ii) to incur substantial outside counsel fees for representation during administrative appeal proceedings.

24. In view of the Department's interpretation of AS 43.05.260, there is no way for the Taxpayer to determine whether amounts timely assessed for any taxable year subsequent to 1978 will later be increased by assessments issued after the three-year limitation period of AS 43.05.260(a) has expired.

25. The Department's interpretation of AS 43.05.260 has also created uncertainty as to the Taxpayer's legal rights and duties under AS 43.05.260 with respect to years subsequent to 1978, which would be eliminated by issuance of the declaration sought in this Complaint.

26. The Department's interpretation of AS 43.05.260 subjects the Taxpayer to a threat of injury in that the Taxpayer could be held liable for additional Alaska taxes for any taxable year.

27. The Department controls the timing of the final administrative decision, and thus the duration of the period during which the Department claims jurisdiction to reaudit taxpayers' returns and raise the amount of tax assessed. For example, the Department has never issued even an informal conference decision in the Taxpayer's 1978 oil and gas corporate income tax case, even though informal conferences were held on the matter in 1983 and 1984.

FIRST CLAIM FOR RELIEF

28. The Taxpayer incorporates by reference paragraphs 1-27 of this Complaint.

29. The Third Amended Assessment is invalid because it purports to amend the First Amended Assessment after expiration of either of the periods provided under 15 AAC 21.700(e) and 15 AAC 21.810(1).

SECOND CLAIM FOR RELIEF

30. The Taxpayer incorporates by reference paragraphs 1-27 of this Complaint.

31. The Third Amended Assessment is invalid because barred by the three-year limitation period of AS 43.05.260(a).

THIRD CLAIM FOR RELIEF

32. The Taxpayer incorporates by reference paragraphs 1-27 of this Complaint.

33. The Third Amended Assessment is invalid because it lacks statutory authority.

FOURTH CLAIM FOR RELIEF

34. The Taxpayer incorporates by reference paragraphs 1-27 of this Complaint.

35. The Department's interpretation of AS 43.05.260 constitutes a "regulation," and is invalid under AS 44.62.030 because it is inconsistent with AS 43.05.260.

FIFTH CLAIM FOR RELIEF

36. The Taxpayer incorporates by reference paragraphs 1-27 of this Complaint.

37. The Department's attempts to assess amounts greater than the amount assessed within the three-year limitation period of AS 43.05.260(a) whenever taxpayers exercise their right to obtain administrative and judicial review of an assessment amount to a denial of the Taxpayer's rights to due process of law guaranteed by Article XIV, Amendments to the Constitution of the United States, and Article I, §1 of the Constitution of the State of Alaska.

WHEREFORE, the Taxpayer requests that this Court:

1. declare either (i) that 15 AAC 21.700(e) prohibits the assessment of any amount in excess of the amount assessed within three years of the date of the Original Assessment, or (ii) that 15 AAC 21.810(1) prohibits the assessment of any amount in excess of the amount assessed within three years from the date the return was due or filed, whichever is later; and

2. declare that AS 43.05.260 prohibits the assessment of any amount in excess of the amount assessed within the three-year limitation period of AS 43.05.260(a), and

3. declare that there is no statutory authority for assessment of any amount in excess of the amount assessed within three years from the date the return was due or filed, whichever is later, and

4. declare that the Department's interpretation of AS 43.05.260, to the effect that assessment of amounts in excess of the amount assessed within the three-year limitation period of AS 43.05.260(a) are permitted, is inconsistent with AS 43.05.260 and, therefore, is invalid, and

5. declare that the Department's interpretation of AS 43.05.260, as applied to the Taxpayer, is void as violative of the Taxpayer's due process rights under Article XIV, Amendments to the Constitution of the United States, and Article I, §1 of the Constitution of the State of Alaska, and

6. award the Taxpayer costs and attorneys' fees necessarily incurred in bringing this action.

DATED this 23rd day of January, 1987.

GUESS & RUDD
Attorneys for Plaintiff

By: _____
Joseph M. Wilson
Louis R. Veerman

7855K

STATE OF ALASKA

DEPARTMENT OF REVENUE

OFFICE OF THE COMMISSIONER

STEVE COWPER, GOVERNOR

P.O. BOX 5
JUNEAU, ALASKA 99811-0400
PHONE: (907) 465-2300

April 27, 1987

The Honorable Ben Grussendorf
Speaker of the House
Alaska State Legislature
P.O. Box V
Juneau, AK 99811

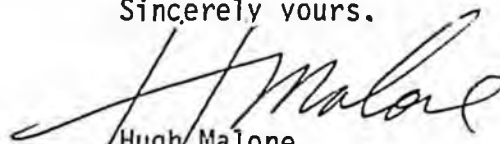
Re: Alaska's Economic Limit Factor Legislation CS HB 164 (Finance) am In
the context of actions in other states

Dear Mr. Speaker:

The following information has been provided to the Governor's office on actions in other states on their oil and gas tax issues. I am providing this to you for your information.

Alaska's situation of being dependent on one primary source of revenue is unique. I believe it is important to understand how oil and gas taxation is being dealt with in other states in the appropriate context. If you have questions on the attached information please call me or Mr. John Hansen in the Department of Revenue Audit Division.

Sincerely yours,


Hugh Malone
Commissioner of Revenue

HM:mkw
87-86

cc: The Honorable Steve Cowper
Members of the Senate
Members of the House of Representatives

Attachments: Hugh's letter of April 27 to Governor Cowper covering Senate President Jan Faiks' memo of April 10 and Jan Faiks' memo of April 10 to all Legislators on oil and gas tax reductions in other states.



Alaska State Legislature

SENATE

Office of the President

P.O. Box V
State Capitol
Juneau, Alaska 99811

April 10, 1987

MEMORANDUM

TO: All Legislators

FROM: Senator Jan Faiks, *JF*
President of the Senate

SUBJECT: Oil and Gas Tax Reductions in other States

Legislatures in other resource states are trying to mitigate the tax burden on the oil and gas industry. This is done to encourage continued exploration and production during the current market situation facing the industry, and thus offset negative impacts on the states' economies and employment levels. Here is summary of what some of the states are doing:

Kansas - HB 2405 would exempt from property or ad valorem taxes all temporary abandoned oil or gas wells and the equipment or material used on the wells. SB 1, which would raise the severance tax exemption on low-production wells, has passed the Senate.

Louisiana - Severance Tax Exemption Plan, wells drilled between July, 1986 and July, 1987 pay no severance taxes through 1990. Economic Acceleration Plan, no tax on development through 1989 for discoveries after July, 1936. Both of these measures became law in 1986.

Mississippi - HB 620 which would provide an exemption from oil and gas severance taxes on certain production from new wells has passed the House.

Montana - SB 383 would exempt the first 24 months of production from new wells from the net proceeds tax.

North Dakota - HB 1667, which would have provided for a two-year moratorium from the extraction tax for all new well and a four-year moratorium from the extraction tax for wildcat wells, failed. SB 2078 which provides a two-year exemption from the 6.5% extraction tax for any well started after March 31, 1987 and completed by July 1, 1989 passed the Senate. SB 2079 which provides a gradual reduction over a five-year period in the 6.5% oil extraction tax to 3.5% and provides for a one-year moratorium from the 6.5% tax on all new wells drilled also passed the Senate.

Oklahoma - HB 1139 would exempt all EOR production from severance taxes until either the payback is completed or 3 years have passed, has passed the House.

Texas - HB 949 makes provisions relating to exempting oil and gas produced by stripper wells from production taxes.

Wyoming - HB 275 which allows severance taxes on carbon dioxide to be a direct credit against severance taxes on oil produced by injection of the gas, has passed both houses of the Legislature.

STATE OF ALASKA
DEPARTMENT OF REVENUE

M E M O R A N D U M

TO: The Honorable Steve Cowper
Governor

FROM: Hugh Malone *Hugh*
Commissioner of Revenue

DATE: April 27, 1987

SUBJECT: Senate President Jan Faiks Memorandum of April 10, 1987
on Oil and Gas Tax Reductions in Other States

Our Department has completed a cursory review and analysis of the various legislation that Senator Faiks points out other states have introduced to mitigate the effects of the current market condition on the oil and gas industry. In response, my staff has contacted the Department's of Revenue in each of these states to verify what is really happening.

We have found this memorandum to be incorrect in the factual analysis of each states legislation. The twelve pieces of legislation referenced in Senator Faiks memorandum generally apply to stripper wells with very low production. To qualify for tax exempt status, each well must be put into production within specific dates. Some states exempt the first 10 to 50 barrels of oil produced per day. More importantly states such as Texas only exempt oil production from tax when the price per barrel falls below a set amount. The fiscal impact of the various legislation is minimal to the states that have passed these bills.

Following is a review, state by state, of Senator Faiks' comments and the comments of other states tax authorities:

1. Kansas - HB 2405

Senator Faiks' memorandum states:

"... would exempt from property or ad valorem taxes all temporary abandoned oil or gas wells and the equipment or material used on wells."

Actual Status:

Applies to only temporary abandoned property. This property has already been given a zero evaluation if they are not producing, therefore would have no fiscal impact to the state. The bill has little chance of passing this session.

SB 1

Memorandum states:

". . . would raise the severance tax exemption on low-production wells, has passed the Senate."

Actual Status:

Applies only to stripper wells of 2,000 ft. depth producing five barrels a day or less, fiscal impact is minimal. Bill has little chance of passing. It has been stalled in House Committee. The combined loss of revenue if both bills did pass to the state would be \$5.5 million. The total revenue raised from oil and gas taxes in Kansas is approximately \$100 million which represents 6%-7% of their entire budget.

2. Louisiana -

Severance Tax Exemption Plan

Memorandum states:

". . . wells drilled between July, 1986 and July, 1987 pay no severance taxes through 1990."

Actual Status:

HB 673 applies only to new oil wells drilled between July 15, 1986 and July 15, 1987. Exempts severance tax on the first 50 barrels of oil per day and only until the well has produced 10,000 barrels. Applies only if price of oil is \$21.00 a barrel or lower. Is repealed in 1990. Fiscal impact will be minimal.

Economic Acceleration Plan

Memorandum states:

". . . no tax on development through 1989 for discoveries after July, 1986."

Actual Status:

This exemption covers only "wildcat wells." These are wells on certified new fields provided the price of oil stays below \$29.50 per barrel and the well is drilled between July 1, 1986 and July 1, 1990. Fiscal impact is minimal.

3. Mississippi - HB 620

Memorandum states:

". . . would provide an exemption from oil and gas severance taxes on certain production from new wells has passed the house."

Actual Status:

HB 620 did not pass.

Another bill, SB 2111, did pass. This bill provides an exemption for the first 50 barrels per day for wells with a depth of 12,000ft. or less and exempts 100 barrels for wells with a depth of 12,000ft. or greater, provided wells are drilled between March 15, 1986 and July 1, 1987 and the average price of oil is \$25.00 a barrel or less. Exemption expires June 30, 1990.

4. Montana - SB 383

Memorandum states:

". . . would exempt the first 24 months of production from new wells from the net proceeds tax."

Actual Status:

It has passed both houses and the Governor is expected to sign. However, the bill covers only the first 12 months of production and pertains solely to the mill rate calculation for county property tax purposes. Has no impact to state revenues.

5. North Dakota

HB 1667

"Failed"

SB 2078

Memorandum states:

". . . provides a two-year exemption from the 6.5% extraction tax for any well started after March 31, 1987 and completed by July 1, 1989 passed the Senate."

Actual Status:

This bill deleted an exemption for royalty owners interest from the oil extraction tax. It passed. This is a revenue positive tax measure expected to raise approximately \$4.6 million in the next two fiscal years.

SB 2079

Memorandum states:

". . . provides a gradual reduction over a five-year period in the 6.5% oil extraction tax to 3.5% and provides for a one-year moratorium from the 6.5% tax on all new wells drilled also passed the Senate."

Actual Status:

Provided for various rule and regulation changes. Provided for a 15 month exemption from oil extraction taxes and reduced the rates from 6.5% to 4% thereafter for new wells drilled after the bill passed. Also reduces rates from 6.5% to 4% on certain wells utilizing tertiary recovery systems and certified stripper wells. Only in effect if oil prices are below \$33.00 a barrel. Revenue impact is minimal. Expected to reduce oil revenues by \$4.66 million over the next two fiscal years. Both bills combined are expected to be revenue neutral.

6. Oklahoma - HB 1139

Memorandum states:

". . . would exempt all EOR production from severance taxes until either the payback is completed or 3 years have passed, has passed the House."

Actual Status:

This bill is sitting on the Governor's desk, he is expected to veto. The bill applies only to certain exploratory wells, at certain depths. Fiscal impact would reduce production taxes by less than 7%. Total revenues raised by oil production taxes account for less than 20% of the entire operating budget for the state.

7. Texas - HB 949

Memorandum states:

". . . make provisions relating to exempting oil and gas produced by stripper wells from production taxes."

Actual Status:

Bill is stalled in House and has little chance of passing. The Comptroller of Texas stated, "Texas can't afford to lose the \$18 million that this bill would be giving to the oil companies." The bill itself exempted only stripper wells, that is 10 barrels of oil or 60,000 cubic feet of gas produced in one day. The exemption only applying if the price of oil was \$14.00 a barrel or less

8. Wyoming - HB 275

Memorandum states:

". . . which allows severance taxes on carbon dioxide to be a direct credit against severance taxes on oil produced by injection of gas, has passed both houses of the legislature."

Actual Status:

This bill has now become law. It applies only to tertiary recoveries utilizing carbon dioxide gas and is only applicable as a credit when the severance tax has been already paid on the gas being utilized for the recovery process for oil which will have the tax applied to it. This could be viewed as a "double taxation" issue. The Wyoming Department of Revenue has projected that this legislation will have such a minimal impact they did not prepare fiscal notes for the bill.

Governor Cowper
April 27, 1987
Page 6

Alaska's dependency on oil and gas production is responsible for over 85% of our total revenue. This is in sharp contrast with the next highest state, Texas, which has an oil and gas dependency of about 20% for its state operating budget. The Comptroller of Texas stated in March of 1987 "That this over-reliance on severance taxes has twice proven an unreliable way to pay for state government. That's a lesson Texas cannot afford to learn a third time. Let's fix the problem."

How do other states raise revenue? Income and sales tax. Every state mentioned in Senator Faiks' memorandum has an income or sales tax. States with an income tax have received a windfall from the 1986 Tax Reform Act and many states are looking at ways to reduce some of those taxes accordingly.

In conclusion, we do not agree with Senator Faiks' portrayal of what the other oil and gas producing states are doing for the industry. We have requested from all states contacted copies of the bills. We can provide you with a more complete analysis should you so desire once we have received this additional information.

SC/HM/JNH/tb

10/7/86

HISTORY OF OIL AND GAS TAX LAW

Severance Taxes

In 1955 the Alaska Legislature enacted two bills which imposed a tax on the production of crude oil and natural gas in the state. One of those measures, which imposed a 1% tax on the gross value of production, was the foundation from which the state's existing oil and gas production properties tax evolved. The other statute, that has since been repealed, was a conservation tax of five mills for each barrel of oil and every 50,000 cubic feet of gas produced.

Between 1955 and 1967 no changes were made in the production taxes. Then, in 1967, the legislature convened in a special session to provide statutory relief for the victims of the Fairbanks flood. Faced with extraordinary costs associated with the Fairbanks disaster, the legislature enacted an additional one percent disaster severance tax on the gross value of oil and gas production.

In 1968 the legislature raised the "regular" production tax from one percent to three percent, but did not change the one percent disaster severance tax or the five mill conservation tax.

In 1970, the legislature, by amendment, embodied a progressive or "stairstepped" rate structure for oil based on average daily production per well. The rates were three percent on the first 300 barrels per day, five percent on the next 700, six percent on the next 1,500 and eight percent on the production exceeding 2,500 barrels per day. Gas production was taxed at four percent. Since the one percent disaster severance tax and the five mill conservation tax were simultaneously repealed, there was no increase in the overall nominal gas tax rate.

In 1972 the Joint Pipeline Impact Committee requested legislation be enacted to protect state revenues from unacceptably low wellhead prices at Prudhoe Bay. The committee anticipated that low prices would result from high pipeline tariffs that could stem from either inadequate tariff regulation or construction cost overruns, or both. In response to that request the legislature enacted a unit of production (cents-per-barrel) tax with a credit for royalties paid to the state. If the cents-per-barrel tax, minus the royalty credit, exceeded the tax collected under the existing

percentage-of-value method, then the cents-per-barrel tax would be payable. Litigation concerning the validity of this new tax began on the heels of enactment.

The 1973 Special Session of the Legislature made several changes to the 1972 law. The royalty credit provision was repealed. The effective tax rate that would apply to oil production was increased by increasing the effective floor of the cents-per-barrel tax from \$2.65 to \$3.375. Instead of four "stairsteps" there were three: the first 300 barrels a day from a well were taxed on the higher of five percent of the oil's value or \$0.16875 per barrel, the next 700 at six percent or \$0.2025 per barrel, and all production over 1,000 barrels a day at eight percent or \$0.27 barrel. In addition, the cents-per-barrel amounts increased or decreased by two cents for each degree of API gravity above or below 27 degrees. Thus a complete schedule of three unit-of-production rates (one for each "stairstep") could have been established for various API gravities. The whole schedule of rates was in turn to be increased or decreased monthly based on changes in the Wholesale Price Index for crude oil, published by the U.S. Bureau of Labor Statistics. The tax on gas production remained a simple four percent of value. In addition, an oil and gas regulation and conservation tax at a rate of \$0.00125 per barrel removed or sold was enacted during this legislative session.

In 1976 no changes were made to the production tax rates, but the legislature did replace the "cash price prevailing" language with "prevailing value" and enacted a section titled "Determination of Gross Value". The changes made it clear that value was to be determined by using reasonable costs of transportation to determine the value at the point of production. The legislature found the terms price and value were not necessarily synonymous and that taxable gross value was to be determined by subtracting reasonable transportation costs from the full consideration realized by the producer at the point of sale.

The production tax was amended again in 1977 when the legislature adopted an economic limit factor (ELF) for the purpose of reducing the effective production tax rate as the amount of production from a lease or property declines. The nominal tax rate for oil was set at 12.25 percent and 10 percent for gas. However, the effective rate was determined through the use of the ELF. The cents-per-barrel and cents-per-mcf rates were also subject to the ELF. Nominally they were 6.4 cents per mcf (corresponding to a 64 cent per mcf floor), 60 cents per

barrel for "old oil" (a \$4.90 per barrel floor) and 80 cents for all other oil (a \$6.53 per barrel floor). Before being reduced by the ELF, the cents-per-barrel amounts were adjusted up or down by a half-cent for each degree above or below 27 degrees per API gravity. There was no automatic escalator for the unit-of-production rates; instead, the Department was to recommend changes to the rates that were appropriate in light of transaction prices and market conditions. Also, the removed and sold standard that historically was used as the measure of taxable production was changed to a produced standard. At the same time, and as a result of Alaska's protracted royalty litigation with oil and gas producers in the Cook Inlet area, the definitions of the point of production were either established or better defined.

It is also noteworthy that some of the complexities of this 1977 legislation caused the Department of Revenue to promulgate the first production tax regulations.

The remaining major amendment to the production tax statute occurred in 1981. The nominal rate of tax on oil was changed from 12.25 percent to 15 percent on any oil produced after June 30, 1981 from a lease or property that was in commercial production prior to that date. The nominal rate on oil produced from a lease or property coming into production after that date was to be 12.25 percent during the first five years of production and 15 percent thereafter. Modifications also were made to the economic limit factors for both oil and gas. The major impact of this legislation changed the effective rate of this tax on over 90 percent of the oil produced in Alaska from approximately 11.5 percent to 15 percent.

On the following page is a summary of production events and tax changes by year beginning in 1954.

OIL AND GAS PRODUCTION AND TAX TIMELINE
9/19/86

- 1954 BLM ISSUED 272 OIL AND GAS LEASES
- 1955 ONE PERCENT OIL AND GAS PRODUCTION TAX
- 1955 CONSERVATION TAX OF FIVE MILLS PER BARREL
AND FOR EVERY 50,000 CUBIC FEET OF GAS
- 1957 SWANSON RIVER OIL FIELD DISCOVERED
- 1959 KENAI GAS FIELD DISCOVERED
- 1962 COOK INLET OIL DISCOVERED
- 1967 ONE PERCENT DISASTER SEVERANCE TAX
- 1968 OIL AND GAS PRODUCTION TAX INCREASED FROM ONE TO THREE
PERCENT
- 1968 PRUDHOE BAY OIL DISCOVERED
- 1970 THREE TO EIGHT PERCENT "GRADUATED" PRODUCTION TAX
(BASED ON PRODUCTION LEVELS)
- 1970 CONSERVATION AND DISASTER SEVERANCE TAX REPEALED
- 1970 GAS PRODUCTION TAX INCREASED TO FOUR PERCENT
- 1972 CENTS PER BARREL "FLOOR" ON PRODUCTION TAX
- 1973 20-MILL OIL AND GAS EXPLORATION, PRODUCTION AND PIPELINE
TRANSPORTATION PROPERTY TAX
- 1973 THREE TO EIGHT PERCENT PRODUCTION TAX (BASED ON LOWER
OUT-PUT LEVELS) PLUS TIED AN "ESCALATOR" TO THE CENTS
PER BARREL FLOOR.
- 1973 OIL AND GAS REGULATION AND CONSERVATION TAX
OF ONE-EIGHTH OF A CENT PER BARREL
- 1973 OPEC QUADRUPLED WORLD MARKET PRICE FOR CRUDE
- 1975 20-MILL RESERVES TAX
- 1977 -NOMINAL 10 PERCENT PRODUCTION TAX ON GAS
-NOMINAL 12.25 PERCENT PRODUCTION TAX ON OIL
-ADOPTION OF ECONOMIC LIMIT FACTOR (ELF)
- 1977 20-MILL RESERVES TAX EXPIRES
- June 20,* 1977 PRUDHOE BAY OIL BEGAN FLOWING THROUGH TAPS
- 1978 OIL AND GAS CORPORATE INCOME TAX (SEPARATE ACCOUNTING)

1979 PRUDHOE BAY WELL HEAD PRICES INCREASED FROM \$5.80 PER BARREL IN JANUARY TO \$10.57 IN JUNE AS A RESULT OF THE LOSS OF IMPORTS FROM IRAN

1981 -OIL AND GAS CORPORATE INCOME TAX (REPEAL SEPARATE ACCOUNTING AND ADOPTED MODIFIED APPORTIONMENT)
-15 PERCENT PRODUCTION TAX(ON ANY OIL PRODUCED AFTER JUNE 30, 1981 FROM A LEASE OR PROPERTY THAT WAS IN COMMERCIAL PRODUCTION PRIOR TO THAT DATE. THE NOMINAL RATE ON OIL PRODUCED FROM A LEASE OR PROPERTY COMING INTO PRODUCTION AFTER THAT DATE WAS TO BE 12.25 PERCENT DURING THE FIRST FIVE YEARS OF PRODUCTION AND 15 PERCENT THEREAFTER)

History of AS 43.21,
Oil and Gas Corporate Income Tax

1978 - 1981

In 1978, the Legislature enacted the Oil and Gas Corporate Income Tax, AS 43.21. Basically, 43.21 is a separate accounting method wherein all of the income and expense elements are defined by statute. Income is divided into three types: (1) income from oil and gas production; (2) income from oil and gas pipeline transportation; and (3) income from any other activities.

The determination of taxable income from oil and gas production starts with the calculation of gross income. Gross income from the production of oil and gas is basically the gross value at the point of production. There are several ways of determining that value including using actual prices or value received, posted prices in the same field or prevailing prices of oil and gas in the same field. The deductions from gross income in order to arrive at the net taxable income include:

- royalties paid in kind or in value
- production property taxes paid
- direct costs of operating the lease or property
- depreciation based on the units of production method
- amortization of lease acquisition payments and taxes paid prior to commencement of commercial production
- interest expense not capitalized during construction
- expenses of unsuccessful exploration of oil and gas in the state including acquisition costs, abandonment of properties, dry-hole costs (only subsequent to abandonment of a lease), and geological and geophysical exploration costs related to the abandoned properties
- general overhead and administrative expense
- income from the production of oil and gas which is divided among the regional native corporations under the Alaska Native Claims Settlement Act
- windfall profit tax

Interest and overhead are presumed not to exceed the corporation's total interest and overhead expenses multiplied by a fraction of which the numerator is the corporation's real and tangible personal property used directly in the production of oil and gas from a lease or property in the state and the denominator of which is all such property of the consolidated business. A corporation may rebut this presumption by satisfactorily demonstrating its actual expenses in Alaska are greater.

The net income of oil and gas pipeline transportation, basically, is the net operating income that is reported to the Federal Energy Regulatory Commission (FERC) or that would be reported to that commission in the case of pipelines that are not regulated by FERC. That method is modified by adding back taxes on or measured by net income. There are also limitations on interest and overhead expenses that may be deducted.

Income from activities other than the production of oil and gas from a lease or property in the state or pipeline transportation of oil or gas in the state is apportioned to the state. The determination starts with the total taxable income and then adding, if appropriate, income of member(s) of the worldwide consolidated business not required to file under the U.S. Internal Revenue Code less that portion of the entire income attributable to production and pipeline transportation of oil and gas worldwide. The apportionment formula is modified so that the numerator and denominator of the property, payroll, and sales factors are each calculated without reference to that portion of property, payroll, or sales directly related to the production of oil or gas or the pipeline transportation of oil or gas in the state.

IMPACT OF 1981 SLA, ch. 116 (SB 524)

Chapter 116 of the 1981 Session Laws of Alaska amended the oil and gas corporate income tax and the oil and gas severance tax in the following manner:

1. Prior to the amendments, AS 43.55 provided for a tax on oil production amounting to 12.25 percent of the gross value at the point of production modified by the economic limit factor (ELF) set forth in AS 43.55.013. The ELF factor on Prudhoe Bay production during FY 1982 was approximately .9249 which led to an effective rate of 11.33 percent. The ELF on Cook Inlet production in FY 1982 averaged approximately .2864 which led to an effective rate of 3.51 percent. The tax rate on gas was 10 percent of the gross value at the point of production modified by an ELF factor.

2. The new law increased the nominal tax rate to 15 percent on oil production (except that for fields commencing commercial production after June 30, 1981, the rate would be 12.25 percent for the first five years). The ELF was also modified so that if the actual calculation resulted in an ELF greater than 0.7 a factor

of 1 would be used. See AS 43.55.011(b) and AS 43.55.013(b)(4). Thus the actual tax rate on Prudhoe Bay production became equal to the nominal rate ($15\% \times 1 = 15\%$), the Kuparak rate became 12.25% ($12.25\% \times 1 = 12.25\%$) and Cook Inlet during FY 82 was approximately 4.3% ($15\% \times .2864 = 4.3\%$). The gas severance tax rate was unchanged although the gas ELF factor calculation was modified. See AS 43.55.013(g). The increased severance tax rates were made effective July 1, 1981, the beginning of FY 82.

3. The oil and gas corporate income tax method set forth in AS 43.21, known as separate accounting, was repealed and a new modified apportionment scheme was enacted effective January 1, 1982. These provisions can be found in AS 43.20.072. The new method for attributing oil and gas income to the state combined with the introduction of a graduated rate structure set forth in AS 43.20.011(e) decreased revenues from the overall corporate income tax.

REPRESENTATIVE
SAM COTTEN
DISTRICT 15



P.O. BOX 296, EAGLE RIVER, AK 99577
POUCH V, JUNEAU, AK 99811

ALASKA STATE LEGISLATURE
HOUSE OF REPRESENTATIVES

March 4, 1988

Mr. Leon Hess
Chairman
Amerada Hess Corporation
1185 Avenue of the Americas
New York, NY 10036

Dear Mr. Hess:

I have just seen a copy of your March 2 letter to Senator Coghill about the proposed legislation to provide relief for Seal Island development.

My reaction to your letter was 100% positive. It is a pleasure, after years of working in the Legislature, to read the words of a corporate chairman who also recognizes and wants to protect the interests of the people of Alaska.

I agree with you that there could be enormous benefits from the development of marginal fields in Alaska. Last year, the House of Representatives passed a bill (HB 164) that would have decreased the severance tax on marginal fields around the state. It also would have repealed the scheduled tax break for Prudhoe Bay and Kuparuk producers, and was therefore opposed by the major lessees in these two units. The only industry support that the bill ended up receiving was from Conoco, which might have been able to keep producing at Milne Point. For now the bill appears to have died in the Senate, but I have asked the Department of Revenue to indicate what kind of severance tax benefits the bill might have produced for Seal Island development. I might add that this bill had the Governor's full support.

At any rate, I appreciate your letter and look forward to meeting you someday when you are in Alaska, or I am in New York, if that would be possible. And we will continue looking for ways to enhance marginal field production for the benefit of the industry and Alaska's citizens.

Sincerely,

A handwritten signature in cursive script that reads "Sam Cotten".

Rep. Sam Cotten, Co-Chair
House Resources Committee

Original sponsor: Rules/Governor

1 IN THE HOUSE BY THE FINANCE COMMITTEE
2 CS FOR HOUSE BILL NO. 164 (Finance) am
3 IN THE LEGISLATURE OF THE STATE OF ALASKA
4 FIFTEENTH LEGISLATURE - FIRST SESSION

5 A BILL

6 For an Act entitled: "An Act relating to the oil and gas properties pro-
7 duction tax; and providing for an effective date."

8 BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF ALASKA:

9 * Section 1. AS 43.55.013(b) is repealed and reenacted to read:

10 (b) The economic limit factor for oil production of a lease or
11 property shall be computed according to the following formula:

12
$$(1 - [PEL/TP]) \exp ([55,000,000 \times WD] / [PEL \times TP/Days])$$

13 where: PEL = the monthly production rate at the economic limit;

14 TP = the total production during the month for which the tax
15 is to be paid;

16 WD = the total number of well days in the month for which
17 the tax is to be paid;

18 Days = the number of days in the month for which the tax is to
19 be paid; and

20 where "exp" indicates that the expression following it is an exponent.

21 * Sec. 2. AS 43.55.013(d) is amended to read:

22 (d) The monthly production rate at the economic limit for a
23 lease or property is presumed to be 300 barrels times the number of
24 well days for the lease or property during the month for which the tax
25 is to be paid. The taxpayer or the department may rebut this pre-
26 sumption at a formal hearing under AS 43.05.240 by providing clear and
27 convincing evidence of a different monthly production rate at the
28 economic limit for the lease or property. The hearing shall be held
29 before February 15 of the year or within six months after commencement

Hess loses its effort for tax, royalty relief

By PATTI EPLER
Daily News reporter

A "personal and confidential" proposal by oil magnate Leon Hess to Gov. Steve Cowper, aimed at cutting costs on a Beaufort Sea project Hess' company is pursuing, has been turned down by the governor as being a bad deal for the state.

So Hess, chairman of Amerada Hess Corp., now says his company will suspend drilling at Northstar/Seal Island, a pair of gravel islands near Prudhoe Bay a few miles off the coast of the North Slope.

Amerada Hess and other oil companies have announced discoveries of commercial quantities of oil at the site. However, the companies never have revealed how much oil they think the reservoir might hold. The state estimates the field contains about 300 million barrels of recoverable crude, a small

field by North Slope standards.

The 73-year-old Hess was in Anchorage last month hoping to convince Cowper to support legislation that would free Amerada Hess from paying royalties and taxes on Northstar production. Hess wants the state to waive the payments until an estimated \$1.8 billion spent to develop the field and build a subsea pipeline has been made up.

Hess pointed out the company bought the Beaufort Sea leases when oil prices were \$35 a barrel. At today's prices — around \$20 a barrel — Northstar development "is not economic and will not occur" without tax relief, he said.

In exchange for a waiver of royalties and taxes, Amerada Hess would give the state the buried pipeline, once the pipeline was paid off, Hess said. That way, the state could collect tariffs on oil shipped through

the line, and an infrastructure would be in place to encourage other offshore projects to go ahead, he said.

Additionally, Northstar development would create construction jobs as well as permanent employment once production began, Hess said.

The company has spent \$80 million exploring the Northstar prospect and had planned to spend another \$50 million this winter to drill more wells, he said.

But state officials don't think the Hess proposal is such a great deal. Especially, they say, because Hess would not disclose how much oil the company has found and give specific cost and financing estimates.

Without knowing how much oil might be produced and at what cost, the state has no

See Page C-8, HESS

Continued from Page C-1

way of accurately judging what it stands to gain or lose, officials said.

Neither Hess nor other company officials returned phone calls this week to talk about the state's concerns.

In memos to Cowper, state oil and gas and revenue officials advised the governor to reject the proposal.

"The Hess proposal offers some new construction activity — much of which would probably be for modules constructed elsewhere — and an unspecified number of new jobs in return for what, conservatively, is likely to be hundreds of millions of dollars in state revenue," wrote James Eason, state oil and gas director.

"If it served as the precedent for similar state participation in additional North Slope oil and gas developments, this cost could quickly grow to billions of dollars," Eason told the governor.

The Northstar leases carry a 20 percent royalty and a 15 percent severance tax. They also are "net profit" leases, which means the company paid less for the leases at a 1979 sale but agreed to pay the state 91 percent to 93 percent of the profits from the leases, after exploration and production expenses are subtracted.

The Hess proposal "essentially translates to a request

for the state to pay approximately 35 percent of Hess' development costs ... through suspension of its royalty and taxes," Eason said. "Meanwhile Hess ... would recover full construction and operating costs plus interest and overhead."

Despite misgivings about the Hess proposal, Eason said, his office has started reviewing incentives and assistance other states are coming up with to help oil companies that want to develop economically marginal fields. He hopes to have some ideas to help Alaska's oil companies formalized in a couple months, he said.

"Hess" North Star Proposal

ACD 1340145

Anchorage Daily News

Sept. 11, 1987

Mr. James Eason
Director
Alaska Division of Oil and Gas
PO Box 107034
Anchorage, Alaska 99510

Dear Mr. Eason:

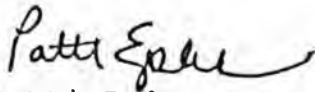
This is a formal request for information pursuant to Alaska's freedom of information and open records laws.

In August, Mr. Leon Hess of Amerada Hess oil company made a proposal to the state having to do with leases and an oil prospect the company owns in the Beaufort Sea. It is my understanding Mr. Hess presented the state with a written proposal/presentation. Further, I understand there has been some correspondence between the state, Governor Cowper and Mr. Hess on the matter.

I would like copies of, or access to, any written or visual material presented to the state by Mr. Hess or his representatives, including details of the proposal. Additionally, I would like copies of any correspondence between state officials and Hess regarding the proposal or other issues related to the company's Beaufort Sea and North Slope leases. I also would like copies of any memos or other communications between state officials on the Hess proposal or issues regarding Amerada Hess leases.

Thank you for your consideration of this request. I look forward to hearing from you within the 10 days required by statute.

Sincerely,



Patti Epler
Staff writer

RECEIVED

SEP 16 1987

DIVISION OF OIL & GAS
ANCHORAGE, ALASKA

MEMORANDUM
DEPARTMENT OF NATURAL RESOURCES

copy file
State of Alaska
DIVISION OF OIL AND GAS

TO: Rod Swope, Special Staff Assistant
Office of the Governor

DATE: September 15, 1987

FILE NO:

TELEPHONE NO: 762-2547

FROM: *James E. Eason*
James E. Eason
Director

SUBJECT: Release of Material in
North Star/Leon Hess
Proposal File

These are the materials in my North Star/Leon Hess proposal file. Materials which are clearly not confidential include the original letter from Leon Hess to Governor Cowper, as well as a copy of the bound Hess Proposal document which Mr. Hess delivered to Governor Cowper at our last meeting. Materials for which you may or may not want to raise the executive privilege argument include all of the documents which I am transmitting by telecopy. I look forward to our discussion.

Enclosure

1067E

DELIVER TO: <i>Rod Swope</i>	LOCATION: <i>Governor's Office</i>
FROM: <i>James Eason</i>	LOCATION: <i>Oil + Gas</i>
TELEPHONE/TELECOPIER # <i>465-3585</i>	TO: NUMBER OF PAGES <i>16</i>
TRANSMITTING CN/SPEED _____	DATE <i>9/15/87</i> TIME <i>2:30</i>
PHONE FOR PROBLEMS-NAME/NUMBER _____	<i>Robert Keith 762-2547</i>
COMMENTS _____	

400 1340148

The Hess proposal literally invalidates the competitive leasing process. Other sale participants submitted bids based upon the expectation that lease terms, including the payment of royalties and taxes, would be required.

Hess' claim of non-economic development cannot be substantiated until the field limits have been fully delineated. By Hess' own admission, additional delineation wells are required. Until recoverable reserves are known and development costs are calculated, it is entirely premature to assume that the field cannot be developed. While oil prices have risen more than 100 percent in the last twelve months, operating costs, including rig rentals and labor have remained low. If this trend continues, Hess' expectations must change. A good example of the dangers of accepting Hess' assumptions is provided by the experience of Sohio and its partners at Endicott. That development was budgeted at more than \$3.2 billion, yet it came in ahead of schedule and for only \$1.2 billion!

The proposal essentially translates to a request for the state to pay approximately 35 percent of Hess' development costs (including pipeline costs) through suspension of its royalty and taxes. Meanwhile Hess (through both its operating company and its transportation affiliates--both pipeline and marine vessels) would recover full construction and operating costs plus interest and overhead. It is important to note that this is not a temporary waiver with future repayment of foregone royalties and taxes after project payout; it is suspension of all state revenues which would otherwise ordinarily accrue until payout with no retroactive recovery. Only prospective payment of royalties and taxes would occur on the then remaining production. If the project is truly as marginal as Hess claims, there could be very few reserves remaining.

The proposal provides every incentive for Hess, through each its affiliates, to pad costs and delay payout. Every dollar spent on operation transportation, construction and overhead would defer payout, and thus the time when royalties and taxes would be payable. To make matters worse, the state would be in no position to effectively monitor or control project costs. The precedent of the Hess proposal would invite requests from similarly situated lessees at nearby fields, including Pt. Thomson, Tern Island, and Milne Point, which is currently shut-in.

In the final analysis, the Hess proposal offers some new construction activity (much of which would probably be for modules constructed elsewhere) and an unspecified number of new jobs in return for what, conservatively, is likely to be hundreds of millions of dollars in state revenue. If it served as the precedent for similar state participation in additional North Slope oil and gas developments, this cost could quickly grow to billions of dollars.

If the state decides to pursue some sort of marginal field assistance, there are numerous options to consider which, unlike the Hess proposal, would treat all lessees equally, and which could be tailored both to quantify beforehand and to minimize the state's revenue loss--both features which the Hess proposal does not offer. The state could agree to undertake a review of industry proposals, as well as recent legislation from other states, to determine if there are options the governor could agree to support. Copies of two recent articles from the Oil and Gas Journal, as well as a News Release from the government of Canada describing the approaches of other energy producing states and Canada are attached.

Buddy
Malone

AMERADA HESS CORPORATION

LEON HESS
Chairman of the Board

RECEIVED

SEP 11 1987

1185 AVENUE OF THE AMERICAS,
NEW YORK, NEW YORK 10038
(212) 997-8400

HAND DELIVERED
GOVERNOR'S OFFICE

September 9, 1987

Personal and Confidential

Honorable Steve Cowper
Governor
State of Alaska
Pouch A
Juneau, AK 99811-0101

Dear Governor Cowper:

I appreciate your courtesy in giving me the opportunity to meet with you, Deputy Commissioner Gorsuch and Mr. Basch concerning our Northstar/Seal Island Prospect in the Beaufort Sea. I wanted you to know that, regretfully, we have made the decision to suspend drilling operations at Northstar/Seal island. Amerada Hess will not proceed with its delineation drilling program at Northstar/Seal Island in this coming winter season. We have released the Glomar Beaufort Sea I, the vessel which was to perform this work.

I am committed to working with you and your staff with the aim of seeing this project ultimately go forward to development. Based on what we know to date, Northstar/Seal Island is a valuable asset of our Company and, we believe, of the people of Alaska. But I must be plain in stating that we will not be able to bring Northstar/Seal Island to production under current and foreseeable world oil prices without relief from Alaska royalty and severance tax burdens. Without such relief, the project's cash flows will never be sufficient to pay out development costs, and without the assurance of payout of development costs, Amerada Hess will not be successful in obtaining the project financing necessary to undertake a project of this magnitude.

I want to review several very important points we touched on during our meeting.

1. Amerada Hess is not seeking special relief. We are suggesting that incentives, in the form of tax and severance forgiveness for a period of time, be adopted to encourage the development of smaller Alaskan oil fields. Northstar/Seal Island, based on current reserve estimates, is such a smaller field and deserving of such relief. Without this incentive, development of Northstar/Seal Island, as well as other, smaller prospective oil fields, is not economic and will not occur. This would be a great loss for all concerned.

2. The State of Alaska loses nothing by adopting such legislation. It seems obvious to me that Alaska's revenues will in fact be enhanced over time, rather than diminished. Without relief these smaller fields will not be brought into production. If Alaska does nothing to encourage development, it is unlikely that Alaska will ever receive any revenue from these potentially productive fields. There is no cost to providing relief from severance taxes and royalty -- only the potential for future gain through net profits and royalty and severance taxes paid in full on oil produced after the project pays out.

It was mentioned in our discussions that Alaska has spent two billion dollars in less than a decade on the development of energy programs. Our proposal is both cost and risk-free to the State, with long term, beneficial economic and social consequences.

3. The incentives Amerada Hess believes Alaska must adopt are not novel. A number of oil-producing states, notably among them Louisiana, Mississippi, Montana, New Mexico, North Dakota and Oklahoma, have already acted to suspend or reduce severance tax and/or royalty payments to encourage drilling activities. Internationally, Canada has been very aggressive in the reduction of tax and royalty burdens to promote exploratory drilling, including a five-year royalty free period for new wells. The United Kingdom has for some time encouraged the development of smaller fields through effective life-of-the-field relief from the U.K. Petroleum Revenue Tax. Norway is considering similar legislation. We can provide you with details on what other oil-producing states and countries are doing, but the point I want to make is that Alaska would not be alone in seeking to encourage, through royalty and severance tax relief, the development of otherwise uneconomic fields such as Northstar/Seal Island. Indeed, many other oil producing states and countries have already recognized the need for and long-term benefit of adopting such legislation.

4. We are not wedded to the proposal to contribute the project's subsea pipeline to the State, or to any particular form of that proposal. Our proposal to build and contribute to Alaska the subsea pipeline serving Northstar/Seal Island is intended to provide a positive, long-term benefit to Alaska, in recognition of the State's cooperation in promoting development of the field through royalty and severance tax relief. Tariffs will be paid by all users, including Northstar/Seal Island and other nearby prospective fields. Experience dictates these nearby fields will be oil productive, and development of these fields will be encouraged if pipeline transportation is already in place. I reiterate, as stated in my July 10 letter, that Amerada Hess does not seek to involve in any way the credit of the State, or any State authority, in the financing of the Northstar/Seal Island Project through this proposal. Most importantly, we recognize that the proposal, as well as any alternatives, require substantial discussion and further definition.

As I flew home after our meeting, I was much discouraged with my obvious failure to explain adequately our Company's proposals. Amerada Hess cannot go forward without your support. We had no choice but to take the disappointing step of halting further exploratory work at Northstar/Seal Island. My hope is that over time we will be able to demonstrate to you and your staff the great benefits to Alaska, not only in jobs but in future revenues, of providing incentives for small field development, and so gain your support for the required legislative program to secure such relief. I look forward to working with you and your staff towards this goal.

Sincerely,

Frank Hess



STATE OF ALASKA
OFFICE OF THE GOVERNOR
JUNEAU

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AUG 31 1987


DIV. OF OIL & GAS
DIRECTOR'S OFFICE

M E M O R A N D U M

TO: Garrey Poska
Chief of Staff

DATE: August 26, 1987

PHONE: 465-3500

FROM: 
Rod Scope
Special Staff Assistant
to the Governor

SUBJECT: Request for
Briefing Meeting
with the Governor

This morning I held a conference call/meeting with Commissioner Malone (in my office) and Lennie Gorsuch (on the phone in Anchorage) to debrief on the Governor's meeting that occurred with Mr. Leon Hess earlier this week.

Issues Summary

Per our discussion, we collectively agreed that the Governor should be briefed as soon as possible on two issues that were raised at the meeting with Leon Hess. Specifically, (1) a desire by the Governor to know more about the background and credentials of a person named Kurt Wulff. (as a person who is reported to be knowledgeable about the oil industry), and (2) the need for additional information about Leon Hess' proposal.

Laura has tentatively scheduled a briefing for 9:00-9:30 a.m. in the morning for the Governor.

Need for Briefing

To brief the Governor on his requests and to let him know who is following up on his concerns/frustrations. He also needs to know about some very recent discussions with petroleum companies that occurred with Lennie and Jim Eason (the discussions are relevant to Amerada Hess) before he takes any independent actions or has further discussions with anyone relative to this issue.

Finally, the Governor needs to know about efforts underway by DNR to examine special state incentives as they relate to the health and well-being of the oil industry at both a national and local level.

Current Agency Involvement

DNR staff was able to brief the Governor before the meeting with Leon Hess. The Department of Revenue also provided input and has been involved in this exercise. The issues involve state oil and gas leases and state royalty, interest from these leases which in turn directly affects the Department of Revenue and their various projections.

State Policies

The principal state policies involved are (1) the policy of adhering to standard conditions of our state leases, and (2) allocation of state royalty oil, interest and taxes. Obviously, these policies indirectly affect others that are being developed based on amount of revenue being received by the state from oil and gas development.

Next Step

The Governor may be going to Washington, D.C. the first week in October. At that time he may want to meet with Kurt Wulff, Leon Hess, etc. Therefore, our follow-up should be completed by then.

Resources Required

None

Recommendation

None

**DNR Briefing
Governor Steve Cowper
August 24, 1987**

Leon Hess Meeting

--State permits for delineation drilling on North Star Prospect

--Hess Proposal

- *Pipeline to TAPS
- *Royalty deferral
- *Severance tax deferral

Takeda/ Hiraki Meeting

--Alaska Pacific Refinery

--Fox Energy

--Gas Reserves Tax

Incentives/relief for industries in Alaska

Rod Swope
Special Staff Assistant
to the Governor

August 21, 1987

Seal Island Proposal

Hugh Malone, Commissioner
Department of Revenue

I agree completely with the Department of Natural Resources reserve on the Seal Island Project proposal as set set out in document 0998E. There will be plenty of time after completion of delineation drilling to evaluate the need of any subsidies to the lessee.

I would also point out that our present severance tax ELF provides reduction in the tax rate for marginal cost production. The lessee's claim that a 15 percent severance tax is too high ignores this fact. In addition the lessee can apply for exploration credits and royalty reduction on meeting certain conditions under AS 38.05.180, which is also ignored by the lessee.

The proposal by the lessee should be reviewed after the delineation drilling is completed.

MEMORANDUM
DEPARTMENT OF NATURAL RESOURCES

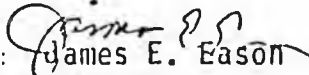
State of Alaska
DIVISION OF OIL AND GAS

TO: Lennie Gorsuch
Deputy Commissioner

DATE: August 21, 1987

FILE NO: C O N F I D E N T I A L

TELEPHONE NO: 762-2547

FROM: 
James E. Eason
Director

SUBJECT: Preliminary Thoughts on
the Hess Proposal for
Royalty and Tax Relief

This letter responds to your request for my preliminary thoughts on the Leon Hess proposal for Northstar royalty and tax relief. Because these are only preliminary thoughts, I will simply list them, without extensive analysis or careful organization.

* In addition to policy concerns, the extent of the legal constraints on legislative power to grant royalty and tax waivers are uncertain at this time. First, there may be a legal question whether a legislature has the authority to bind future legislatures on a tax matter. That is, a tax waiver may not be possible as a matter of law. Second, section 6(i) of the Alaska Statehood Act, the Alaska Constitution or the common law public trust doctrine may be interpreted to prohibit the waiver of royalties. In the 6(i) suit, Trustees for Alaska convinced the Alaska Supreme Court that section 6(i) of the Alaska Statehood Act requires rents or royalties for hardrock mining rights. The same ruling would apply to oil and gas rights in state "mineral lands" acquired under section 6 of the Statehood Act. Notably, the Alaska Supreme Court did not reach the issue as to whether the state constitution and the common law public trust doctrine require rental or royalty income. The case is still active (the state has petitioned the United States Supreme Court) and the Alaska Court could still reach the state law issues.

* Hess proposes to "contribute" the pipeline as a "bonus" to the state, and asserts that his proposal would not "involve in any way the credit of the state in the financing." (emphasis in original.) This rhetoric obscures the reality that the state could potentially pay much more, and have many fewer protections under the Hess proposal than if it were directly involved in the financing.

If directly involved in extending or guaranteeing credit, the state would have some control over the terms and extent of the project and could insist upon significant protections. These could include fixed loan limits, a definite loan term, fixed payments, a security interest and other protections. Instead, under the Hess proposal, the state is, at best, "buying" the pipeline (even that is not guaranteed, since there may never be any payout) for delivery at some unknown time in the future (when the useful life of the pipeline or field could be nearly over). The "price" to the state is substantial; 35 percent of the lease revenues (20 percent royalty waiver plus 15 percent tax waiver). The total amount paid would guarantee recoupment of capital costs and interest to the leaseholders for both the pipeline and the field development.

However, the state would gain title only to the pipeline. To be sure, the lessees would be contributing some of their share of lease revenues to project cost recoupment. However, some of their share of revenues would go to operating costs -- costs which they would have to cover out of their share before taxes and royalties are determined. This makes it extremely difficult (impossible??) to calculate how much of the pipeline (and field development) the state would be paying for, but it clearly would be a lot. Any characterization of the contingent conveyance of the pipeline as a "bonus" or "contribution" is entirely disingenuous.

- * If the state entertained this proposal, it will have no principled way of refusing other resource developers the opportunity to subordinate state tax and royalty income to full recoupment of the development costs. It would reverse a long tradition here, as well as in other mineral-producing states, of requiring that the royalty be free of costs and risks of development. For these reasons, this extraordinary proposal should probably be considered, if at all, in the context of general legislation which treats all state oil and gas (and coal and gold and ???) lessees in the same manner.
- * Hess has clearly not revealed all the relevant information he currently possesses, and even the data which he has revealed are clearly insufficient to provide the basis for informed decision-making. Missing, but essential elements would include the reserve estimates, cost estimates, price estimates, payout estimates and much more are essential pre-decisional background. Hess characterizes his offer as involving "short-term relief" to the oil companies in return for "long-term benefits" to the state. However, there is no basis for concluding the relief will be short or limited in any way (especially monetarily), or that there will be benefits, let alone long-term ones. Unless Hess can predict the future with absolute certainty, he cannot defend these claims.
- * Even if the state were predisposed to some sort of "relief", this particular proposal cannot be properly considered until more details are known. The interaction between this proposal and the unit agreement which would presumably govern development and cost-sharing with other lessees needs to be clarified. For instance, how would operating costs be determined and paid? The interaction between this proposal and its impacts on federal royalty and taxes would have to be clarified. Will Hess ask for a similar waiver of federal royalties and taxes for those reserves underlying federal acreage? Many accounting details could have tremendous impact. How would overhead be treated? What rate of return should Hess be allowed for its capital contribution? How would the tax value of depreciation of the field development facilities and pipeline be factored? Would the pipeline be a common carrier from the inception? How would tariff payments, designed to recoup pipeline development and overhead costs and provide profit, be treated under the Hess proposal?

As you know, pipeline tariffs are typically deductions from gross revenues for purposes of determining the net amount on which the royalty or tax percentage is taken. Here, presumably, tariff revenues would be applied at least partly to project cost recovery. Would the APUC's or FERC's cost recovery schedule for tariff purposes control when the state might gain title to the pipeline and commence to receive royalties and taxes? Or, would some oil revenues be used to supplement tariffs to accelerate pipeline cost recoupment? Would the state's tariff on the pipeline (after it gets it) be limited to operating costs and profit because of the fact that the state would not get title until after all capital costs are recouped? Doesn't sound like much of a deal to me, particularly if the state is saddled with dismantling and removing the structure.

- * At the time of the lease sale, Hess won the leases by outbidding rivals and paying the bonus. The bidding was based upon the understanding that the bonus and rents only entitled a lessee to hold and explore the lease; production would carry a 20 percent cost-free royalty burden, a tax burden and a net profit burden. Hess is proposing that the two major burdens, royalty and tax, be eliminated for a potentially unlimited time--conceivably for the life of the field if prices were to fall sufficiently. Before this unprecedented post facto change is made to the state's leasing program, the impact on the integrity of the leasing process should be carefully evaluated. I guess this could be characterized as a polite way of saying..."I can't imagine what the worth of any of our oil and gas leases might be after the first step was taken."
- * Hess proposes that the waivers terminate after payout on all capital expenses, with interest. How would this proposal interact with reimbursement of operating costs, which presumably would be paid on a current basis from production income? Would overhead and profits be allowed as part of the capital costs? As part of the operating costs?
- * What safeguard or control would the state have on the amount of capital costs and the rate of interest?
- * What safeguards would the state have against imprudent or manipulative establishment of the amount of "lease revenues"? Under the lease, the state has protections to ensure proper royalty value. For instance, the royalty value of production sold under a non-arm's-length contract would be valued at market value or contract price, whichever was higher. When there is no royalty due, some equivalent protection would be appropriate.
- * The proposed legislation would be special legislation, restricted by Alaska Constitution, Article 11, Section 19. The last oil and gas-related special legislation, Conoco's SB 430 (1986), to lessen royalty obligation for Milne Point, did not pass the legislature. What, if anything, is needed is a comprehensive marginal field statute, which addresses royalty

Lennie Gorsuch
August 21, 1987
Page 4

and/or tax relief for all the state's marginal fields, with definition of marginality and limits on relief, rather than ad hoc "fixes". Royalty reduction restriction in AS 38.05.180(j) would be superseded by the new legislation (new legislation controls old legislation), but the exemption should be expressly stated to avoid litigation.

- * The proposal to suspend royalty and tax until "payout" raises all the horrors of administering NPSLs without the protections. There would be no regulations or base provisions to say which expenses (out-of-state expenses, overhead, etc.) went towards payout. Litigation would be likely no matter how the standards were expressed. Similarly, there would be no safeguards against "gold-plating", where Hess builds large fancy facilities to transfer to a construction area or subsidiary to delay "payout".

As I said, these thoughts are not very well organized--my apology--but given the momentum this proposal seems to be gathering and the overwhelming downsides (in my parochial view), I thought it best to get some talking points on paper. I see the value of creating jobs--but not a few jobs for a short period of time in exchange for the evisceration of the state's leases and the potentially gigantic revenue losses which would follow. The state would literally need a new division to entertain all the proposals. Don't forget Exxon's shut-in "marginal field" at Pt. Thomson.....

0989E

(Ch)
cc: JMB
Jim Casan
LO

Please review
Rod Swope asked
LNR & Revenue
to develop a position
on this ASAP
(Tom Koester was
in cell but is out
of town)

August 5, 1987

DEPARTMENT OF
NATURAL RESOURCES

AUG 04 1987

COMMISSIONER'S OFFICE
JUNEAU

Please send up
time to discuss
this with
Commissioner
next week
JMB

Mr. Leon Hess
Chairman of the Board
Amerada Hess Corporation
1185 Avenue of the Americas
New York, NY 10036

Dear Mr. Hess:

I enjoyed the opportunity to meet with you in June to discuss your proposed activities in Alaska.

Your letter regarding the need for legislative initiatives to relieve the Northstar project of state royalty and severance tax burdens just arrived. I have asked some of my professional and technical staff in the Departments of Natural Resources and Revenue to review the proposal and suggestions contained in your letter. I will contact you once I have had an opportunity to confer with my staff.

I am hopeful that we will be able to work with you to develop a mutually acceptable and beneficial plan.

Sincerely,

Steve Cowper
Governor

bcc: Commissioner Judith M. Brady
Department of Natural Resources
Commissioner Hugh Malone
Department of Revenue
Tom Koester, Assistant Attorney General
Department of Law

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AUG 06 1987

DIVISION OF OIL & GAS
ANCHORAGE, ALASKA

SC/RS/mw

AMERADIA HESS CORPORATION

1185 AVENUE OF THE AMERICAS,
NEW YORK, NEW YORK 10036
(212) 997-8400

LEON HESS
Chairman of the Board

July 10, 1987

Personal and Confidential

Honorable Steve Cowper
Governor
State of Alaska
P.O. Box A
Juneau, AK 99311-0101

Dear Governor Cowper:

I appreciate your taking time from your busy schedule to meet with us to hear an update on Amerada Hess' Northstar Prospect in the Beaufort Sea. We believe the Northstar Prospect has significant potential for economic benefit both to our company and to the people of the State of Alaska.

Sadly, this project can never be brought to development, given the collapse in world crude oil prices that occurred in 1986 and the changed economic realities of the oil business, unless the legislature of the State of Alaska recognizes the need for and implements realistic development incentives. As you know, other oil producing states have recently undertaken actions to revitalize exploration and production programs within their borders.

In 1979, when bids were submitted for the Federal/State Beaufort Sea Oil and Gas Lease Sale in which the Northstar Prospect leases were awarded, the world price of crude oil was \$35.00 per barrel. Projections were for steadily increasing prices over the years ahead. Today, although some stability has returned to world oil markets, the economics of the market are completely different. In the aftermath of the OPEC-inspired price war, world oil prices stand in the \$20.00 per barrel range. No one reasonably anticipates a return to world crude oil prices of \$35.00 per barrel until at least after 1995.

That is why under current reserve assumptions development of the Northstar Prospect is not economic and will not occur. Simply put, with a 20% royalty burden and a 15% severance tax, the project will never pay out.

To make development even marginally viable, we need your support of legislative initiatives to relieve the project of Alaska State royalty and severance tax burdens. Without such relief, no company can proceed.

AGO 1340162