

ALASKA LEGISLATURE SPECIAL COMMITTEE / SUBJECT FILES 8672

630 SCOMM20: HOUSE INT. COMM. OIL & GAS LEASING POLICY 1979

5. ENVIRONMENTAL STIPULATIONS.

- a. What is the state's position on seasonal drilling requirements?
- b. Will a backup drill rig be required in case of blowouts, such as the recent Pemex Bulf of Mexico disaster? (app. yearly cost for such a backup rig?)
- c. What provisions are being made for the protection of the Boulder Patch?

6. UNITIZATION

- a. What is the status of cooperative arrangements with the feds regarding cooperative and unit agreements for exploration and production?

7. LOCAL GOVERNMENT

- A. What effect with the North Slope Borough's Coastal Zone Management Plan have on the sale?

Alaska State Legislature • House of Representatives
Interim Committee on Oil and Gas Leasing Policy

Rep. Joe McKinnon
Chairman
Rep. Chat Chatterton
Rep. Sam Cotten
Rep. Joe Hayes
Rep. Hugh Malone
Rep. Bill Miles
Rep. Brian Rogers



727 N St., Suite 2
Anchorage, Alaska 99501
907-276-1955

September 28, 1979

Robert E. LeResche, Commissioner
Department of Natural Resources
Pouch M
Juneau, Alaska 99811

Re: Beaufort Sea Lease Sale Issues;
Public Hearing of October 8, 1979

Dear Bob:

Attached is a Committee Staff Report which details some of the important issues in the upcoming Beaufort Sea lease sale. We know you are currently studying these issues in depth, and are encouraged by your efforts in preparing for the lease sale. We offer our analyses and recommendations as an aid to you and the Governor in your deliberations. The decisions soon to be made on how to lease the Beaufort Sea are among the most critical ones to face this Administration. Accordingly, we believe that as many points of view -- and analyses -- as possible be considered.

Because of the importance of the issues, we feel that they deserve a thorough public discussion before final decisions are made by the State. With your cooperation, we have scheduled a Public Hearing in Anchorage for Monday evening, October 8, 1979, at 7:00 p.m. in room 402 of the State Court House. In the Hearing we will present the Committee Staff's recommendations, detailed below, for your comment, and discuss the current results of the work by your own staff. Our goal is to have the best possible information at your disposal during the hectic pace of the next few weeks. We understand the pressures and deadlines you face, and appreciate your willingness to discuss Beaufort issues with the Committee in a public forum.

Our recommendations, more fully explained in the Staff Report, are summarized as follows:

1. Leasing Procedures on Disputed Acreage: The State should not agree to the proposal by the Federal government to use the Federal Sliding Scale/Bonus Bid system on disputed acreage. The

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Committee has proposed an alternative -- and better -- sliding scale system for the disputed acreage in our September 14th Report to you.

We also urge you to reject the Federal government's proposal to lease all structures under a single bidding system. Besides usurping State authority, the proposal is reprehensible because of the lack of certainty in delineating structures prior to actual exploration.

2. Consideration of Projected Revenues: The current budget picture of present surplus and future deficit should be a primary concern in choosing a bidding method. A long-term view, spanning several decades, is a prerequisite to a wise decision on bidding methods. Our analyses demonstrate that the Bonus Bid system, by failing to delay lease revenues, denies a fair return to the people of Alaska and abrogates the fiduciary responsibility of the State government to its citizens.

3. Post-Lease Sale Administration: In the interests of State and industry efficiency, the Committee recommends that production audit functions be consolidated into one department.

4. The Department's Economic Analysis: At this time the Committee has had the opportunity to review DMEM's rough draft economic analysis. We compliment DMEM on the quality of the draft report. As you have indicated, the final report will consider the additional economic issues of competition, split-leasing, on-structure drilling and reserved acreage. All these ideas have played an important role in oil development throughout the world, and deserve consideration by Alaska.

We note from the latest timetable of your Department's activities, that on October 5th the final regulations in 11 AAC 83 will be forwarded to the Lieutenant Governor and that the completed Economic Analysis will be dispatched from DMEM to you. The Committee would very much like to receive a copy of each of these documents that same day. Obviously, they are of central importance to the October 8th Public Hearing.

The Committee looks forward to meeting with you and your staff on Monday evening, October 8th.

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Sincerely,

House Interim Committee on
Oil and Gas Leasing Policy



Joe McKinnon, Chairman

Attachment

cc: Governor Jay Hammond
Thomas K. Williams, Commissioner, Department of Revenue
Thomas Cook, Director, DMEM
Representative Terry Gardiner
Representative Russ Meekins
Senator Clem Tillion
Senator John Sackett
Senator Bill Sumner
Cecil D. Andrus, Secretary of the Interior
Alaska Outer Continental Shelf Office (BLM)
Alaska Oil and Gas Association

MEMORANDUM

TO: Joe McKinnon, Chairman
House Interim Committee on Oil & Gas Leasing Policy

FROM: Committee Staff

DATE: September 28, 1979

RE: Beaufort Sea Lease Sale Issues and Recommendations

The committee staff has been carefully reviewing preparations and developments regarding the upcoming Beaufort Sea lease sale. In addition to extensive research, this has involved multifaceted contacts with numerous industry officials and myriad State and Federal agencies, as well as attendance at official briefings on developments.

The result is this report. Though it is not offered as an exhaustive study of every point involved in the sale, it is nonetheless a carefully drawn analysis of important issues, accompanied by our recommendations. We hope it will be helpful for the Committee's upcoming public hearing the night of October 8th, not only to Committee members, but to State and Federal officials and representatives of the oil industry as well.

BIDDING SYSTEMS ON DISPUTED ACREAGE

The genesis of the attempt to resolve the problem of bidding systems on disputed acreage was the Memorandum of Understanding which Governor Hammond and Interior Secretary Andrus signed in March of 1978, which outlined the policies and procedures that were to be followed in the proposed joint Federal/State oil and gas lease sale in the Beaufort Sea. This Memorandum of Understanding ("the M.O.U.", as it is generally known) was the culmination of negotiations between the State and Federal governments on procedures to be followed in leasing properties whose title is still in dispute in the Beaufort Sea area. Negotiations had been in progress since December 1975, when Governor Hammond had cancelled a proposed Beaufort Sea lease sale because of the land dispute.

The objectives of the Memorandum of Understanding, stated in its introduction, are:

- to identify general policies and procedures for joint leasing and administrative activities associated with an oil and gas sale in the Beaufort Sea.
- to develop guidelines for allocating costs and responsibilities associated with pre-sale and post-sale administration.
- to describe a means of refining the principles cited in this document into specific processes and responsibilities. (M.O.U., p. 1).

Since its signing, the Memorandum of Understanding has been used as the cornerstone for policy decisions in the joint sale negotiations between State and Federal officials. In a Press Release issued on March 2, 1978, before he signed the Memorandum of Understanding, Governor Hammond stated that it expressed two fundamental principles:

One: That neither party may unalterably determine policies or practices applying to areas of disputed ownership; and two, that uniform operating guidelines will apply to the entire sale area.

While the Memorandum of Understanding established a set of guidelines for joint sale negotiations, it did not create any binding or contractual obligations on either of the parties.

The parties agree that nothing contained in this Memorandum of Understanding or done pursuant to it shall affect in any way the legal rights, interest, and claims of the parties in the area of the Call for Nominations described above. Though this Memorandum of Understanding is intended to be a morally binding guidance document, it is not intended to create enforceable contractual duties. (M.O.U., p. 8).

The Memorandum of Understanding establishes who has legal jurisdiction and management responsibility over disputed acreage within the sale area. This is the most significant point expressed in the M.O.U. The State has jurisdiction over undisputed State

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land. The Federal government has jurisdiction over all disputed acreage and the undisputed Federal acreage. To quote directly from the Memorandum:

Being more inclusive, Federal standards and legal requirements will as a general principle, apply to activities on all tracts which contain any Federal acreage and/or disputed acreage. State standards, policies and legal requirements will apply to tracts containing exclusively undisputed State acreage. Each entity shares the responsibilities as an equal partner on all decisions pertaining to tracts containing disputed acreage or to tracts of split ownership and neither party may unilaterally determine policies or practices which apply to disputed or split tracts. (M.O.U., p. 1).

What this means is that disputed acreage must be leased under a Federal bidding system, but the State must concur.

Both the State and Federal governments have considerable statutory authority in choosing a bidding system for an oil and gas lease sale: the State authority pursuant to AS 38.05.180(f), its oil and gas leasing statute; the Federal authority comes from the Outer Continental Shelf Lands Act, 43 U.S.C. 1331-43. Both Federal and State laws allow variations of bonus, royalty, or net profit bidding with provisions for work commitments.

The State is presently in the administrative review process on regulations to implement the provisions of AS 38.05.180, as it was amended by ch 155 SLA 1978 and ch 65 SLA 1979. The proposed Article 2 of 11 AAC 83 on Net Profit Share Leasing establishes procedures for calculating the net profit share due to the State from any net profit share lease issued by the Department of Natural Resources (hereinafter referred to as "DNR" or "the Department"). The proposed Article 1 of 11 AAC 83 authorizes the Department to offer a lease on a sliding scale royalty to be "chosen at the commissioner's discretion".

The net profit share system proposed by the Department in the proposed Article 2 of 11 AAC 83 is an "Investment Account" system commonly referred to as a front-end capital recovery system. This system allows a lessee to fully recover costs plus interest before the State collects a net profit share from a lease. The decision to use an "Investment Account" system was based on an economic analysis of various types of net profit leasing systems, which was a joint effort of DNR and the Department of Revenue.

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The proposed Article 1 of 11 AAC 83 authorizes a sliding scale royalty but does not specify a particular type of sliding scale royalty system. The system to be used is to be "chosen at the commissioner's discretion". The primary purpose of the proposed 11 AAC 83.183, as we stated in earlier reports, appears to be administrative flexibility.

The Federal government is still in the midst of evaluating different net profit share leasing systems, but agrees that a front-end capital recovery system is economically superior to other bidding systems. However, the Federal government is undecided as to whether to allow interest on development costs, as the State has opted for in its "Investment Account" system, or whether to apply a multiplier to pre-production expenses in lieu of an interest rate. The State considered this point irrelevant as both systems are economically so similar. But, because of this debate, the Federal government will not have net profit leasing regulations in place in time for the sale.

Our preliminary research supports the Department's choice of the Investment Account system as the optimal leasing system. By a simple cash-flow analysis, it can be demonstrated that if the State defers the taking of income until the oil companies have recovered their costs, the State will receive more in total discounted present-value dollars, because of the relatively high discount rate used by an oil company. Money received 15 or 20 years downstream is worth very little to the oil companies and does not figure significantly in their bids. The oil companies are more than willing to share a larger percentage of the downstream income in return for early recoupment of costs. This is in accordance with the State's time preference for money, because the State has a significantly lower discount rate than an oil company. Downstream income is worth considerably more to the State.

Recently, the State was informed that because of bureaucratic delay the Federal government would not have regulations for net profit share bidding in place in time for the sale. Because of this delay, the Federal government has offered the State only two bidding choices for disputed tracts: (1) cash bonus bid with a fixed royalty; and (2) cash bonus bid with a fixed sliding scale royalty.

As the analyses the Committee submitted to the Department on September 7th and 14th concluded, the Federal Sliding Scale Formula would result in significantly less income to the State than the alternative developed by the Committee, which it termed "the Committee Sliding Scale". State income, the September 14th Report

concluded, is reduced because of two reasons: (1) the Federal Sliding Scale Formula relies too heavily on the bonus, thereby reducing the effective royalty percentage; (2) the Federal Sliding Scale Formula ignores the realities of unitized production by using a logarithmic formula which establishes the royalty on a tract-by-tract basis. What this means is that if two units produce identical amounts of oil, but one of the units contains more tracts than the other, the royalty percentage from the unit with more tracts is lower.

The problems encountered with the Federal Sliding Scale Formula do not occur with the Committee Sliding Scale. However, it is important to emphasize that, in our opinion, the Committee Sliding Scale, superior as it is to the Federal Sliding Scale Formula, is still inferior to the Net Profit Investment Account System. The Committee Sliding Scale royalty was developed as a possible compromise for use on disputed acreage, mainly because the Federal government did not have sufficient time to implement net profit share leasing regulations and its Sliding Scale Formula is unsuitable.

It has been the consistent policy of the Department that if the Federal government does not come up with a system which will maximize State income, the State will not agree to lease the acreage. In the public hearing the Committee held in Anchorage on August 13, 1979, DNR Commissioner LeResche, testifying before the Committee, was asked what was the State's position if it is determined that it is locked into an inferior bidding system on disputed acreage because the Federal government has not adopted net profit leasing regulations. The Commissioner's response, in effect, was that if in the Department's economic analysis it is determined that the Federal options are significantly inferior to other options available under State law, he would propose withdrawing that acreage from the sale. The Commissioner further reiterated this position in Fairbanks on August 23, 1979, in a briefing for the Governor on the Beaufort Sea lease sale. In regard to bidding systems on disputed acreage, Commissioner LeResche stated that

"If the cost of agreeing is that we will choose a bidding method that is less favorable to the State, just to lease the acreage, our decision will be that we won't do it. We'll cancel the disputed leases."

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On September 18, 1979, Committee Staff met with a representative of the Federal government regarding use of the Federal Sliding Scale Formula. Based on the results of the Committee's analysis of September 14th, three alternatives to the present Federal Sliding Scale Royalty Formula were discussed for use on disputed acreage. The alternatives are: (1) changing the factors in the Federal Sliding Scale Formula to increase the effective royalty and decrease the bonus; (2) consider using the Committee Sliding Scale as described in the September 14th Committee Report; (3) withdraw the disputed acreage from the sale. These alternatives are to be considered for inclusion in the Secretarial Issue Document (SID) for the Beaufort Sea sale, which will be presented to the Secretary of the Interior before he makes his final determination regarding the sale.

In is our recommendation that the State should not agree to lease the disputed acreage under the original Federal Sliding Scale Formula.

Bidding Systems on Single Structures

The Federal government has consistently maintained that all tracts on each structure should be leased using the same bidding system. This recommendation was presented to State officials in a July 13th meeting in which Thomas Cook, Director of DNR's Division of Minerals and Energy Management (DMEM) and spokesperson for the State, tentatively agreed to the recommendation.

If the State finally does agree to this recommendation, it will be giving up a significant amount of management authority for deciding bidding systems within the proposed sale area. If a structure as delineated prior to the sale is located primarily on State acreage but a small portion of that structure crosses into disputed acreage, the structure would have to be leased under a Federal bidding system. As the Federal government has offered only two bidding choices (Cash Bonus/Fixed Royalty and Cash Bonus/Sliding Scale Royalty), this limits the State's options severely. To make matters worse, it is possible that after exploration the only oil or gas discovered in the structure will lie under State land. This would mean the State would be collecting lease payments under a Federal bidding system for an oil pool located beneath State land.

The rationale for this single-bid-per-structure recommendation is the oil industry claim that leasing a structure under different bidding systems will make it difficult, if not impossible, to Unitize. This question arose before while HB 854 (which ultimately became ch 155 SLA 1978) was being considered by the Senate Resources

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Committee in 1978. In a 5-30-78 memorandum from the Legislative Affairs Agency (LAA) to the Chairman of the Senate Resources Committee, the opinion of the LAA Research Division was summarized thusly:

At the Senate Resources Committee meeting on Friday you received testimony to the effect that the use of differing leasing methods on adjacent tracts, as would be permitted under HB 854, would make it difficult to establish unitized development and production of the pools over which those tracts lie. Generally, our studies of this question, which we have conducted since the matter was first raised several months ago, do not support this conclusion. On the contrary, they show that the incentives to unitize will not be seriously reduced by diverse lease arrangements, and that the difficulties of reaching unit agreements will not be increased as a result of this diversity.

Unitization, as we all know, is basically a conservation technique designed to protect lessees' rights in a field and prevent waste of hydrocarbons. Unit participants are allocated working interest percentages in the field and share costs and revenues in relation to their working interest. Based on the prior research conducted by the Legislative Affairs Agency and our own research, it is our opinion that basic incentives for unitization are present under any bidding system. The primary engineering and economic incentives remain unchanged, i.e., amount of oil, location, geologic considerations, development costs, and efficient management of the oil pool.

In our research on this question, we contacted Bob Jones of the Louisiana Minerals Board, which administers offshore leases in conjunction with its Conservation Division. A number of these offshore leases are administered jointly with the Federal government, and contain different royalty provisions, different tax structures, and many were leased at different times. According to Mr. Jones, none of these differences have prevented unitization from occurring, nor have they caused any problems for Louisiana officials in administering the leases, or for Federal OCS officials in New Orleans for that matter.

We also discussed the matter with Ron Kaplan of the Department of the Interior, who agreed that this recommendation of a single bidding system is not absolutely essential. Unit accounting might become more difficult, he conceded, but it would not actually prevent a field from being unitized.

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Based on our analysis, we see no reason whatsoever why the State should agree to a recommendation that would have the effect of depriving the State of so much management authority. It would undermine the State's authority over undisputed State land by narrowing or maybe even eliminating its choice of bidding systems.

In addition, the single-bid-per-structure recommendation has a practical problem. As Hoyle Hamilton, Chairman of the Alaska Oil and Gas Conservation Commission (AOGC) said in early September at an Anchorage meeting of State and Federal officials on this matter,

"I'm not sure how definite the seismic data will be in determining the location of the structure."

In other words, one could end up trying to match up bidding systems on adjacent tracts that bear no relation to the position of the structure.

Because the location of structures cannot be positively determined, the State should not limit its available choices by agreeing to the Federal recommendation. To make such a compromise, based on imprecise data, would be foolish and not in the State's best interest.

The Department's position on the single-bid recommendation, however, apparently has not yet been resolved. In the Committee's August 13th Public Hearing in Anchorage, Commissioner LeResche indicated to the Committee that the extent to which this recommendation would be adhered to depended upon the relative position of a structure in relation to State and disputed land. In other words, if 95% of the structure was on State land and 5% was on Federal land, the State would not concede to using a Federal bidding system. If the situation were reversed, i.e., 95% of a structure on Federal land and 5% on State land, the Department would agree to use of a Federal bidding system. Commissioner LeResche did not indicate, however, what would happen if half a structure was on State land and half on Federal land.

As the Memorandum of Understanding put it, "State standards, policies and legal requirements will apply to tracts containing exclusively undisputed State acreage". It is our opinion that under no circumstances should the State relinquish any authority over undisputed State acreage.

State Taxes

During the course of State/Federal negotiations, a significant question has arisen over what to do about State taxes

on disputed acreage. AS 43.55.011 requires a lessee to pay a production tax, but Federal law does not. The State also requires oil companies to calculate the amount of State income tax differently from Federal income tax. This results in a higher effective State income tax rate. The differences in the State and Federal tax laws have posed the problem of what to do with what the Federal government considers to be excess State taxes due from disputed tracts.

Most of the lease payments due from a lessee having an interest in an oil pool located beneath disputed acreage will be placed in escrow pending resolution of the disputed lands question. Precise requirements are to be outlined in the Joint Interim Agreement. However, the Federal government has been consistently opposed to collecting State taxes that exceed Federal taxes and placing these in escrow with other lease payments due from disputed acreage. Federal officials feel this will adversely affect bids on Federal tracts. They are, however, amenable to including a provision in each Federal lease which provides that the lessee will be liable for all back taxes plus interest in the event the State ultimately wins the title dispute.

Commissioner LeResche has agreed with the Federal position that State taxes would not be collected and placed in escrow pending resolution of the land dispute, but has, however, indicated that he supports a provision that will require lessees to retain liability for payment of back taxes. In our opinion, State taxes should be collected and placed in escrow, or at the very least the lessee's liability should be spelled out clearly in the Federal lease form.

TITLE TO DISPUTED LANDS

At the end of January, 1979, State and Federal officials approved the Federal/State Leasing & Nomination Map -- the official joint sale map. The joint sale map established specific sale boundaries and its approval was an important procedural requirement in the regulatory preparation for the sale. The map delineated three types of land that would be leased in the sale: State lands, Federal lands, and "disputed" lands. Generally, State lands lie within three miles of the coastline or near-shore islands, while Federal lands lie outside the three-mile limit. The disputed lands are claimed by both the State and Federal governments because of different legal theories on the fixing of boundaries of State coastal waters.

Because the Barrier Islands form a continuous chain of State land offshore, there are actually two categories of disputed

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land. One major portion of disputed land forms an enclave between the shore and the Barrier Islands, which is totally surrounded by State land. This area would be considered State land under the "inland waters" theory; the State has a good chance of prevailing on this theory.

The second area of disputed land lies outside the Barrier Islands. This would be considered State land under the "straight baseline" theory. Based on International Law, this theory holds that territorial boundaries are drawn as straight lines three miles out from the furthestmost land area. A conflicting theory requires three-mile arcs to be drawn around the furthestmost land area. Unfortunately, the baseline theory -- which would work out best for the State -- has been rejected twice by the U.S. Supreme Court.

And the final determination here of who finally is granted title to the disputed land will be decided by the U.S. Supreme Court, which has original jurisdiction in the matter. The State and Federal governments have agreed to settle the issue that way. Accordingly, a lawsuit was filed in the U.S. Supreme Court in June (United States of America v. State of Alaska, File No. 84 Original).

A requisite to the sale, the lawsuit focused originally on the disputed lands delineated on the joint sale map. The lawsuit enables the State and Federal governments to enter into an interim agreement setting out procedures for leasing and handling revenues from the disputed lands. In addition, Attorney General Gross has testified that the State has attempted to raise in the lawsuit the issue of disputed lands in the Colville Delta area and off the shore of the Arctic Wildlife Range.

Unfortunately, since the signing of the joint sale map, Federal officials have attempted to nullify the map and their previous position, calling into dispute the use of two salient points for establishing boundaries of disputed acreage. Those points are Dinkum Sands and the ARCO Pier Dock. Both claims are disadvantageous to the State.

Dinkum Sands

Even though the chances are slim that the straight baseline theory for establishing territorial boundaries will be ultimately upheld by the U.S. Supreme Court, the State still has a decent chance at title to the enclave of disputed acreage within the Barrier Islands per the Submerged Lands Act. But, if Dinkum Sands -- an island, the State claims -- is removed as a salient point for determining State territorial waters, the State's case is weakened considerably. The effect would be to open up the enclave of "State land" within the Barrier Islands. A link would then be created between the disputed

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tracts inside the Barrier Islands and the undisputed Federal acreage beyond the Islands. At stake are 18,035 acres and untold revenues.

The issue of Dinkum Sands first surfaced in a letter dated June 21, 1979 from the Chief of the BLM's Division of Cadastral Survey to the State's Chief Cadastral Engineer, which declared that:

Information has been furnished to this office that the area known as Dinkum Sands shown as upland on Nautical Charts 16046 and 16061 has in fact eroded to such an extent that no upland or low tide elevations remain. As this area is encompassed by the area of the proposed joint Federal/State oil and gas lease sale in the Beaufort Sea scheduled to be held in December, 1979, this office proposes to drop the salient points previously selected on Dinkum Sands and heretofore used for computations of split blocks for the upcoming sale. New split block computations without using the Dinkum Sands salient points will be initiated.

As a small member of the Barrier Islands, Dinkum Sands has appeared on Federal Nautical Charts since at least 1955, but in the maps that are part of the Final Environmental Impact Statement (8-79) and in the Federal proposed notice of sale (8-22-79), the area including and surrounding Dinkum Sands is shown as "disputed tracts".

The BLM's position was buttressed -- later -- by the results of a bathymetric survey for USGS conducted on July 25, 1979 by the R/V Karluk. In a transcribed radiotelephone message to Ed Kempema, a participant in the survey from Erk Reimnitz, another participant, Mr. Reimnitz described what he believed to be Dinkum Sands:

The minimum depth of the shoal was 30 to 40 centimeters and the shoal covered an area approximately 30 meters in diameter. The shoal was composed of very gravelly sand.

Mr. Reimnitz also mentioned that "it was foggy for part of the survey, with a minimum visibility of 100 meters."

State officials have made several visits to Dinkum Sands. On July 11th, Thomas Cook (DMEM's Director), Michael Arruda (Asst. Attorney General), and Claud Hoffman (DMEM's Chief Cadastral Engineer) visited Dinkum Sands. In a sworn affidavit issued on August 2nd,

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Mr. Hoffman testified that:

The sandy, rocky island upon which we landed has large chunks of ice along its northerly and southerly sides and was exposed approximately 3 1/2 - 4 feet above the water level. There appeared to be several such islands in the group extending approximately 1,000 - 2,000 feet in a generally southwesterly and north-easterly (or westerly and easterly) direction. We landed in what appeared to be the middle of this island string.

In my experience as a cadastral engineer and in consideration of my familiarity with the maps of the Beaufort Sea area, I am convinced that the island upon which we landed is part of a group of islands historically known as Dinkum Sands.

In other words, the island was above water, as it was also found to be on August 13, 1979.

On August 23rd, however, State and Federal representatives made a joint visit to Dinkum Sands and found it under eight inches of water. But extraordinary tidal conditions prevailed that day, creating a "tidal surge" that may have resulted in the water level being up to a foot above the mean high tide mark.

In Washington during the week of August 9th, Attorney General Gross negotiated a "settlement" with the Federal government of the Dinkum Sands question. The area in question is to be leased and managed by the State. A joint Federal/State monitoring team will observe the island for a continually acceptable period to determine when the island is above mean high tide (or high water, which is still being negotiated). If the island is under water part of the time, revenues will be split proportionately with the Federal government. The Federal government will receive revenue in proportion to the time the island is under water. This "agreement" affects only leasing, administration, and revenues; ultimate ownership still must be decided by the U.S. Supreme Court. (As of yet, however, no formal written agreement has been reached).

ARCO Pier

The second point of contention to arise since the approval of the joint sale map is the use of the ARCO Pier on the northwest shore of Prudhoe Bay as a salient point for determining the disputed area for the Beaufort Sea sale.

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The ARCO Pier was built in 1974. Two years later the pier was extended to twice its former length under an emergency permit issued by the Corps of Engineers. As of this moment, it is only the extension that is at issue. The issue was put in writing in a letter dated June 15, 1979, from Interior Solicitor Leo Krulitz to Attorney General Avrum Gross. In it, Mr. Krulitz complained that:

When the leasing map for the joint Beaufort Sea sale was being prepared, it came to our attention that the State of Alaska considered the ARCO pier to have extended its coastline. Unfortunately, I cannot concede that valuable Federal land was conveyed to the State through the issuance of an emergency permit, without proper review by this Department or approval by Congress. Therefore, the Federal Government will be forced to require removal of the entire pier to erase any doubt as to the location of the coastline, unless the State is willing to drop its claim. Removal of the pier seems to be a somewhat unreasonable solution to this problem. However, I believe it is equally unreasonable for the State to take advantage of the fact that ARCO's application was not properly reviewed due only to the emergency circumstances. If the State is unwilling to waive its claim in this case, we will feel constrained to refuse approval of all such permits in the future, when a true emergency exists.

The threat of removal now, we assume, is limited to the extension of the pier.

Mr. Krulitz claimed that Federal regulations (33 C.F.R. 320.4(f)) required that his office be consulted before structures were approved which may alter the coastline, and contended that neither the BLM nor his office was given the chance to comment on ARCO's application. The regulation reads as follows, in pertinent part:

All applications for structures or work affecting coastal waters will therefore be reviewed specifically to determine whether the coast line or base line might be altered. If it is determined that such a change might occur, coordination with the Attorney General and the Solicitor of the Department of the Interior is required before final action is taken.

We recently examined the "Beaufort Sea 10" file of the Regulatory Functions Agency in the Anchorage office of the Corps of Engineers, which contains all materials involved in the granting of the permits for the original ARCO Pier and the extension. We found the following items of interest:

- (1) A 12-10-75 letter from the Department of Interior's Fish and Wildlife Service to the Alaska District Engineer of the Corps of Engineers, stating that "Interested agencies of the Department of Interior have reviewed the Atlantic Richfield Co. (ARCO) request for an emergency permit..."
- (2) A 12-15-75 memorandum to the file by William Bleggi of the Regulatory Functions Branch stating that "I informed [Col. Poteat of OCE] that EPA, NMFS, USF&WS and Coast Guard were involved and agreed on the conditions. Also we had touched base with General Rollins (Federal Pipeline Office) and Bill Moses (Interior's General Counsel) who gave their concurrence."
- (3) The 1-6-76 Statement of Findings by the Corps of Engineers stating that "General Rollins of the Federal Pipeline Office, Department of the Interior, was contacted in regard to the proposed project and the conditions that were submitted. Concurrence was received on 15 December 1975 from the Pipeline Office."

We have made no conclusions other than to surmise that a gap in communications of considerable magnitude must exist within the Interior Department.

The above notwithstanding, Harvey Sullivan, Counsel for the Corps of Engineers, contends that the emergency permit was nonetheless issued properly per the 1973 Trans-Alaska Pipeline Authorization Act (43 U.S.C. 1651 et seq), citing 43 U.S.C. 1652(b) as the authority and direction for

the Secretary of the Interior and other appropriate Federal officers and agencies to issue and take all necessary action to administer and enforce rights-of-way, permits, leases and other authorizations that are necessary for or related to the construction, operation, and maintenance of the Trans-Alaska oil pipeline system...

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43 U.S.C. 1652(c) allows Federal officers to waive any procedural requirements of law which they deem desirable to further the interest of the Act. That intent, stated in 43 U.S.C. 1652(a), is to ensure that

the trans-Alaska oil pipeline be constructed promptly without further administrative or judicial delay or impediment.

The extension of the ARCO Pier in 1976 was necessary to allow the unloading of 13 barges trapped in the ice. The barges were loaded with cargo for construction of facilities at Prudhoe Bay.

Although Mr. Sullivan claims the emergency permit was issued properly, he also maintains, loyally, that it was never intended that the extension of the pier be a "permanent structure" to be used as a salient point to measure coastal boundaries. However, ARCO and other officials of the Corps of Engineers believe the pier to be a permanent structure, and the entire pier is an integral part of the proposed plan for the Prudhoe Bay Waterflood Project which was submitted in July 1979 by the Prudhoe Bay Unit Waterflood Task Force as part of the various permit applications. Counsel for the Corps of Engineers has expressed approval of the use of the ARCO dock in the waterflood project.

As stated earlier, only the extension of the pier is at issue at this date. Approximately 765 acres are at stake.

Summary

Sometime in the hopefully not-too-distant future, the U.S. Supreme Court will resolve the disputes over acreage. The actions of Federal officials in the Dinkum Sands and ARCO Pier controversies, however, have caused a cloud of acrimony to hover over the joint sale. Governor Hammond summed it up well in a July 17th letter to Interior Secretary Andrus in which he discussed the Federal government's changes of position on the disputed acreage:

I bring these matters to your attention at this time because they have the potential to create major stumbling blocks to proceeding with the proposed Beaufort Sea sale in December of this year. There are several legal issues involved in the proposed sale requiring intensive discussion and cooperation between the State and the Federal Government. Your department's unilateral attempt to deviate from the already agreed-upon guidelines for determining the

boundaries of State-owned lands and Mr. Krulitz' attempt to coerce the State into abandoning a legitimate legal claim certainly do not foster an atmosphere conducive to cooperation; if anything, they pose a serious threat to the sale being held at all.

But at the briefing for Governor Hammond in Fairbanks on August 23rd, Attorney General Gross, referring to the disputed lands issues, said that "these disputes will not hold up the sale in any way." In the briefing, he had reviewed the Dinkum Sands compromise but made no mention of the ARCO Pier.

REVENUE FORECASTS

The timing of revenues from oil and gas lease sales to fit the State's monetary needs is a critical element in selection of the optimal bidding system -- and one the DNR should not decide unilaterally. In a bonus bid sale with a low fixed royalty, a large portion of the lease payment is made at the front end. In a royalty bid system, payment is deferred until production begins. In a net profit bidding system per the proposed Article 2 of 11 AAC 83, payment is deferred even longer or until there has been sufficient production to allow the lessee to recoup its capital costs.

In determining the timing of income, the Department of Revenue needs to establish the State's appropriate discount rate. This factor determines the State's time value of money and measures the return the State can earn on its investments. Current forecasts predict a huge surplus for the next few years, resulting from recent OPEC price hikes and the ongoing increase in pipeline throughput. The July price hike boosted the State's income from the production tax and the sale of royalty oil, and was compounded by the increase in Prudhoe production to 1.4 million barrels per day (to rise to 1.5 million by December).

The Legislative Finance Division, in a September 5, 1979 Budget Projection, concluded that the State will have a liquid surplus of 3.6 billion dollars during the next fiscal year. This is over 2.5 billion dollars above the amount of the current operating budget. Commissioner of Revenue Thomas K. Williams has testified that his Department's projections developed by the Petroleum Revenue Division (using its PETREV computer model) are substantially the same. Depending upon the rate of growth of the State budget, the surplus revenues can be expected to continue until some time between 1998 and 1995. Sobering deficits are predicted to occur some time during the 1990's as the Prudhoe Bay field reserves are depleted.

This forecast points to the conclusion that the State currently has a negative time value of money. That is to say, it may be better for the State to take a loss of current revenue so as to have more income ten-to-twenty years in the future. This forecast argues strongly for the taking of lease payments in the form of a royalty or net profit share, rather than a front-end bonus.

DMEM's apparent insensitivity to the effect a huge surplus has on the State's discount rate and time value preference for income was recently displayed in a front-page story in the Anchorage Times of September 18, 1979. The article quoted Thomas Cook, DMEM's Director, as follows:

One of the related considerations is the State's need for income and the timing of that income.

"There's a funny thesis that we should be concerned with deferring income," he said.
"Of course the ultimate deferral is never."

Not all State officials, however, feel that deferring State income is "a funny thesis." Thomas K. Williams, Commissioner of Revenue, said at the briefing of the Governor on the Beaufort Sea lease sale on August 23rd in Fairbanks,

"What we are trying to do is optimize the flow of funds through time so we don't have a big valley in terms of revenue in the late 1980's. Perhaps a cataclysm would be a better word of what could happen through the 1990's."

Commissioner Williams also indicated that his Department was going through the exercises of matching budget growth with revenue forecasts. Regarding those analyses, Commissioner Williams stated, at the same meeting:

"We see the State going broke despite the billions of dollars on hand in the early 2000's."

In our opinion, decisions which affect the State's financial position and its time value preference for income, whether from a lease sale or State investment, should be made in close consultation with the Department of Revenue. DNR can assist by providing technical information that would bear on the timing and expected value of revenues from an oil and gas lease sale. However, the choice should be made in large part by the Department of Revenue so as to be as compatible as possible with the State's

actual money needs. Furthermore, it is of critical importance that the State time its lease revenues from the Beaufort Sea to replace declining revenues from Prudhoe Bay in the early 1990's.

There is yet another reason for spreading payment of lease revenues. As experience shows, State income can be more wisely spent if it is stretched out over a period of years, instead of collected in a lump sum. Massive one-time increases strain the ability of policy makers and administrators to properly manage State agencies or programs. A striking example is the ten-fold growth of the University's budget during the 1970's, which created a management crisis that is only now being remedied. Leasing procedures should enable revenues to be timed to ensure wise fiscal management, as well as maximizing economic benefits.

In the August 13th public hearing of this Committee in Anchorage, Commissioner of Revenue Williams said, "We have more revenue anticipated for this fiscal year than we need for our operating budget." The Commissioner added that in general the price increase for crude oil has pushed back the time when the State's current revenue surplus would be exhausted, which would be sometime near the mid-1990's. If a major portion of rent from the Beaufort is collected as a cash bonus payment, it would not fit well with the State's current revenue situation.

POST-LEASE SALE ADMINISTRATION

A major criticism leveled at net profit leasing by DMEM, again, is that post-sale audit difficulties may make net profit share leasing unworkable. In the words of Thomas Cook, "Net profits would be an administrative nightmare". Currently the Department is responsible only for auditing royalty payments from actively producing lease tracts. A net profit share lease would require auditing allowable costs as defined in the proposed Article 2 of 11 AAC 83.

Late in the 1979 Legislative Session, the Legislative Budget and Audit Committee published a report which concluded that:

The Department of Revenue and the Department of Natural Resources should coordinate their efforts to provide a more comprehensive audit program. Even though the oil and gas tax and royalty are treated separately by statute, their bases are so similar that auditing both should be considered one function.

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This conclusion is based on the fact that even though DNR audits royalty and the Department of Revenue audits the production tax, the audit functions are so similar that they should be consolidated in one department.

This issue of audits is further complicated by certain confidentiality requirements which apply to tax information obtained by the Department of Revenue, which may not divulge information regarding taxpayers' returns except in official administrative or judicial proceedings. AS 43.05.230. And though the Department of Revenue conducts field audits for production tax payments (AS 43.55) and the oil and gas corporate income tax (AS 43.21), it may not share this information with DNR. But DNR is not staffed to conduct field audits to verify royalty payments; all DNR does is simple desk audits. Information obtained by the Department of Revenue would greatly increase the accuracy of royalty audits if it could be shared with DNR.

HCS CSSB 51 (Judiciary) am H (1979) would have allowed this very information obtained by the Department of Revenue to be made available to DNR if that information related to the value of oil or gas in which the State has an interest under AS 38.05.180. The bill, unfortunately, failed to pass the House.

A different solution, perhaps a more permanent one, would be to shift the entire audit responsibility to one of the two departments. This question of post-sale administration of a net profit share lease was posed to the Commissioner of Revenue. Commissioner Williams told the Committee that the audit burden, as it related to a net profit share lease, has been reduced significantly because of the similarity of the proposed net profit share leasing regulations to the oil and gas corporate income tax regulations and proposed production tax regulations. Because of this similarity, Commissioner Williams said, auditors from Revenue could double up the functions of the tax audits and a net profit share lease audit.

In our opinion, because the Department of Revenue has been increasing its staff to audit the production tax and corporate income tax, it is the logical choice for audits of net profit share leases. Another point that supports this choice is the fact that the proposed net profit share leasing regulations in 11 AAC 83 are modeled on the oil and gas corporate income tax regulations and the proposed production tax regulations (15 AAC 05.700 et seq). And because of Revenue's familiarity with these audit procedures and the similarity of its regulations to the proposed net profit share leasing regulations, Revenue is the best Department to have the audit responsibility for net profit share leases. This could be achieved in the short-term by an inter-agency agreement, and in the long run by new legislation.

ECONOMIC CONSIDERATIONS

Selection of the bidding system for the Beaufort Sea lease sale is one of the most important economic decisions now facing the State. That decision could affect the State's financial position for several decades. It cannot be taken lightly and must be based on a thorough economic analysis. In the August 23rd Fairbanks briefing of the Governor on the Beaufort Sea lease sale, Commissioner LeResche stated,

"It is not a philosophic question; it is very clearly a technical question. . . . We have fought hard to withhold any serious consideration of bidding methods until we have all the information available to us. . . . That information includes a theoretical analysis of how different bidding behaves under different production scenarios. . . . It includes the final geologic assessment; that is, what we think is there."

We agree with Commissioner LeResche that the choice of a bidding system should be based on the best information available -- with maximizing State income as the primary policy objective.

The responsibility of matching leasing decisions to revenue needs is strictly the landowner's (the State's here). If one system proves to be consistently more favorable under prevailing and alternative situations, that one is the logical choice. To quote from the rough draft of DMEM's Economic Analysis:

If the decision maker consistently selected the alternative having the highest positive expected monetary value his total net gain from all decisions will be higher than his gain realized from any alternative strategy for selecting decisions under uncertainty. This statement is true even though each specific decision is a different drilling prospect with different probabilities and conditional profitabilities. (pp. 17-18).

In other words, the decision-maker must consistently choose the best system for maximizing economic return.

The State has a variety of systems available to it for leasing oil properties pursuant to AS 38.05.180(f). It can lease by requiring a cash bonus, a royalty share, or a net profit share. The State can combine the systems and can require work commitments. The State can

reserve acreage within the sale area, or it can choose not to sell it. The final choice must be consistent with the State's time value preference for income.

From the State's point of view, the decision is simple to conceptualize. First, assume a certain amount of oil, worth X dollars. Then assume it will cost Y dollars for a company to develop it, including a return on its investment. If X is greater than Y, the field is economic.

The only question the lessor (again, the State here) need ask is how to collect Z -- the difference. The crucial question is how to collect Z in a way that will maximize return to the State.

Briefly, the State has three basic choices facing it in the upcoming sale: (1) The traditional system is the Cash Bonus/Low Fixed Royalty system. Under this system, the State sells the lease to the bidder who, at a competitive auction, offers the highest bonus bid. The bonus is paid shortly after the auction. (2) A second choice is to fix a low bonus, or a bonus just high enough to weed out irresponsible bidders, and require the companies to bid a percentage of future royalty. (3) The third choice is to set a low bonus and award the lease to the bidder offering the highest percentage of its net profit. The net profit is simply gross value less cost. A variation of the first system is to either set a higher royalty or net profit percentage and use the bonus as the bid variable.

All the systems involve risk. In royalty or net profit systems, payment is contingent upon a find. If oil or gas is not produced in commercial quantities, the State receives no income. In bonus bidding, the State faces risk that an unexpectedly significant quantity of oil will be found. It also faces the risk that oil prices will rise substantially during the life of a field. In an era when world oil prices are being set politically, the full benefits of those price rises won't necessarily enure to the State under a bonus system. A bonus bid, for reasons explained in this Report, fails to produce a fair return on the resource. This point was explained by Governor Hammond to Don Langston, Exxon's Vice-President of Exploration, at the Fairbanks briefing of August 23rd. The Governor said:

"We're talking about risk which reduces revenue to the State. . . . If we have a field with an enormous net profit and the State took a lower bonus, then there is a risk -- the risk that we get less than we had to if we had chosen net profits."

The bonus system has some bureaucratic appeal. It is simple, requires little skill to manage, and promises occasional successes. For example, in 1974 the Federal government received over

two billion dollars in bonus payments for salt domes off the coast of Florida. But there is a flip side to the bonus system. From 1964 to 1969, the State of Alaska sold the leases that make up the Prudhoe Bay Unit for bonuses totalling approximately 90 million dollars. The current worth of the Unit is well over 100 billion dollars. The battles over taxation so the State could finally obtain a fair share of the value of its field were fought at enormous cost to all parties.

The bonus system has strong proponents within DNR. Speaking on behalf of DMEM, Thomas Cook puts it this way:

"I'm hellbent to see something feasible, that we can administrate. My views are well known. I have a decided bias for proven leasing methods, unless someone can show me what we could accomplish that way (net profits) that we can't accomplish another way."

(Anchorage Times, 9-18-79, p. 2).

Clearly the bonus system accomplishes the task of conveying mineral interests beneath State lands to oil companies. Its ability to ensure maximum economic returns, provide incentives for exploration, and guarantee adequate competition, however, is questionable. In examining how to best maximize State income from a lease, the State should measure this policy against these four economic criteria: (1) Discounting; (2) Incentives; (3) Competition; and (4) Risk. The rough draft of DMEM's economic analysis considers these criteria.

Discounting

In the example of $\$X - \$Y = \$Z$, the basic question is: How does the State want $\$Z$ paid to it? Does the State want $\$Z$ (generally termed economic rent) paid in a lump sum as a bonus, or does it want it spread out over time as a net profit or royalty payment? How much the State receives in bids by the companies is related to their discount rate. The worth of the bid to the State is affected by its discount rate.

The State has a lower discount rate than an oil company. If the State's discount rate is measured by the return on Permanent Fund investments or as DMEM calls it in its rough draft, "the opportunity cost of capital," the State's discount rate is currently around 0.0% in real terms. In other words, the State is barely able to keep its current revenue surplus and Permanent Fund balance from being eroded by inflation. DMEM's rough draft assumes 0.0%; we concur.

An oil company's discount rate is much higher than the State's, because, unlike the State the company's investments are not statutorily restricted. In DMEM's rough draft, its base case assumes 8%. We feel that adding 12% and 16% scenarios provides a fuller, more realistic range for study.

Discounting measures the present-day value of income or spent through time. Measured in real terms, \$100 is worth a lot more to an oil company if it can invest it today and earn up to 16%, than the \$100 is to the State which can only earn 0.0%. DMEM puts it this way in its rough draft:

The difference in private and public discount rates is extremely important in evaluating the relative attractiveness of the various leasing alternatives from the state's point of view. It means that future dollars are worth more to the state than the industry.
(p. 15).

As DMEM's rough draft concludes, against the criteria of discounting, a royalty or net profit share system is far superior to the bonus system for both the State and the oil companies. Companies are in a position to bid more dollars when, during the exploration and development phases, they have the use of the money that would have been paid as a bonus. They are willing to bid more as a net profit share than a bonus or royalty because they are thus permitted to recover their capital outlays, which allows them additional years to plow earnings back into this -- and other -- fields.

Incentives

This second economic criterion is related to the incentives different bidding systems offer the lessee to (1) explore and develop and (2) to recover the maximum amount of oil from a pool.

The systems are also evaluated in terms of their potential ability to encourage economically efficient resource use. For example, a system may generate substantial revenues to the state but discourage the development of marginal fields and encourage abandonment of producing fields before all of the economically recoverable oil is recovered. Other things being equal, it is desirable that all economically recoverable oil and gas be extracted in an efficient (cost minimizing) manner. (DMEM rough draft, p. 2).

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An oft-repeated criticism of royalty or net profit share bidding is that these systems encourage speculative bidding, which will adversely affect exploration and development decisions. Conversely, as DMEM states on p. 6 of its rough draft:

It is also argued that the payment of a large front end bonus will lead to the diligent development of a lease.

We find no concrete evidence, however, to support this latter argument.

Because there is no historical evidence of alternative bidding systems on State leases, we have been limited to examining the actual performance of actual Cash Bonus/Low Fixed Royalty leases to determine whether the detractors of net profit share leasing are right.

Currently pending before the Department are applications for Unitization involving 56 unexplored about-to-expire leases -- leased under a Cash Bonus/Low Fixed Royalty. Unitization here is being attempted to extend the leases without having to bring them into production as required by law. We need not belabor here the worthy concept of Unitization as a conservation practice designed to protect lessees' correlative rights in the development of an oil pool, and the preventing of the waste of hydrocarbons. We have mentioned it earlier in this Report. As we mentioned in a Report to the Department on August 17th, too, Unitization as a device for extending leases is of dubious value in cases where "it is uncertain whether any oil or gas exists in commercial quantities."

Here, however, the issue is not Unitization, but whether the method used in leasing these 56 properties encouraged exploration. All the leases in question were granted to the bidder offering the highest cash bonus payment, with a royalty fixed at 12.5 percent. The operators have not explored any of these leases, even though industry maintains that payment of a bonus will encourage development.

So, while payment of a bonus doesn't necessarily ensure development of a lease tract, there is still the argument that without bonuses you encourage speculative bidding.

This problem supposedly occurs, the industry claims, with royalty or net profit share bidding. This particular

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problem is easily solved, however, by simply setting a moderate fixed bonus high enough to screen out irresponsible bidders. This point is not addressed in DMEM's rough draft -- but should be. And besides setting bonuses, DNR also has the authority to require work commitments, i.e., to require a certain number of wells to be drilled on a lease or in a particular geographic area.

The recent departure from prior State policy evinced in the Duck Island controversy cannot help but discourage speculation. If a company knows that it will in fact be allowed to hold acreage only for the primary term of the lease unless it explores and brings the property to development, it will no longer be in its interest to sit on a lease in anticipation of higher future oil prices. Under the alleged prior State policy, the lessee could use unitization as an excuse for extending the primary lease term. Under Federal law, this problem is surmounted by employment of a five-year lease term. Under State law, the primary lease term is ten years. This point should also be addressed in DMEM's analysis.

What we do find in DMEM's rough draft is the following:

If the value of reserves was growing at 15 percent per year in real terms and the firm's opportunity cost of capital was 10 percent, it is not obvious that the bonus would assure "diligence". (p. 6).

We would merely point out here that the value of the Prudhoe Bay reserves has risen ten-fold during the past decade.

On the point relating to marginal production and extending the economic life of a field, net profit share leasing is clearly the best system. On a net profit share lease the net profit share paid to the State can decline to zero. This is definitely a positive effect in terms of extending the life of a field.

Unless the Commissioner's discretion is invoked per AS 38.05.180(1), the royalty cannot decline below 12.5% under both the bonus and royalty systems. AS 38.05.180(f). Because of this, there is always a contingency payment which may have the effect of shutting down a field. This problem was solved regarding the production tax by applying the economic limit factor, which allows the production tax rate to decline as production from wells declines. A royalty acts economically like the production tax. Both are perceived as costs to the oil company, and may make a marginal field uneconomic.

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As a comparison of net profit share to royalty bidding, note the following point made by DMEM:

The net profits system adopted by the state, because it allows for the capital recovery of additional field investment, is much more likely to encourage secondary efforts. (DMEM rough draft, p. 19).

When a company invests in secondary recovery systems, it reduces the amount it pays as a net profit share to the State.

Competition

It is to the lessor's advantage to attract as many bidders as possible to a lease auction. But under current State leasing policy, there are two deterrents to competition: lack of adequate information on geologic potential, and large up-front bonus payments.

Under current law as interpreted by DNR, well data that relates to the valuation of nearby unleased acreage must be kept confidential for a reasonable time after disposition of the affected area. See AS 31.05.035(c), as amended by ch 160 SLA 1978. Ch 160 SLA 1978 had the effect of locking up data from certain wells adjacent to the proposed sale area. Attempts to repeal the effect of ch 160 SLA 1978 were made by the House during the 1979 Legislative Session, but were unsuccessful. Prior to ch 160 SLA 1978, well data was routinely made public after two years.

The companies without access to this data are placed at a keen disadvantage in the upcoming sale. Companies with proprietary data protected by AS 31.05.035(c) (as amended) contend that they drilled wells in anticipation of a previously scheduled Beaufort Sea lease sale. When that lease sale was cancelled, the companies claimed it was unfair that this data was to become public. In December 1975, Governor Hammond cancelled a Beaufort Sea lease sale scheduled for 1976. All the wells protected by AS 31.05.035(c) were spudded after December 1975. The wells which became public prior to the ch 160 SLA 1978 conclusively confirm the presence of oil and gas offshore in the Beaufort Sea. As Don Langston of Exxon put it at the Governor's briefing in Fairbanks on August 23rd,

"I don't think there is much risk that there is not oil in the Beaufort Sea."

Included as part of the Department's economic analysis should be the effect of reserving the tracts adjacent to acreage where well data is locked up pursuant to AS 31.05.035(c). Because the State has

access to the data, that should make the evaluation fairly precise. If oil is eventually discovered around these tracts, their value would increase dramatically.

Another point on competition is the effect of requiring the payment of a large bonus to acquire a lease. Smaller companies do not have the cash on hand to compete with larger companies on the choicest tracts. By restricting the number of bidders, the State may be losing out in the long run. This point is well-documented in the literature. See, e.g., Alternative Oil and Gas Leasing Policies, A Report to the Alaska Legislature, Mason Gaffney, 1978. The fact that large bonuses screen out smaller companies, combined with the effect a bonus would have on the State revenue surplus, makes yet another powerful argument for use of royalty or net profit share bidding. This point is mentioned on p. 6 of DMEM's rough draft:

Finally, from the lessor's viewpoint, the extent to which the bonus transfers the economic rent to the lessor is extremely sensitive to the level of competition. Paradoxically, it is alleged that the traditional cash bonus system hinders competition because of the requirement of a high front end bonus. Smaller firms lack the financial resources to compete effectively in the bidding process and the geological risk is too great to rely on traditional capital markets for the necessary funds.

Risk

The final economic consideration -- and the one least understood -- is risk. The key to understanding risk is expected value. What course of action will result in the largest net gain from a large number of independent trials? In other words, the odds of success or failure will even out over the long-term, so one should choose the system which will maximize revenues over an extended period of time, not on a tract-by-tract or trial-by-trial basis. DMEM states it this way, by asking:

Does the repeated trial aspect of expected value vitiate its use where each choice has a different set of economic parameters and geological risks? The answer is no. The expected value concept can be applied to leasing decisions if it is applied consistently to all decisions. (DMEM rough draft, p. 17).

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The question of risk is also addressed in the paper by Hayne E. Leland, Professor of Business Administration at the U. of California (Berkeley), regarding the Department's proposed Net Profit Share Leasing regulations. In the introduction to his paper, Dr. Leland states that

Because of risk, firms may require higher rates of return than the state. Risk sharing through net profit share leasing will be advantageous, in that expected revenue will be [sic] higher. The risks borne by the state will also be higher, however.

Risk sharing is particularly advantageous to the State, because it bears different risks than an oil company. Oil companies must evaluate risk on a tract-by-tract basis, and will discount their bids accordingly. The State, however, averages its risk over all tracts. Accordingly, the risk that a particular tract on which a company happens to be bidding is dry is much greater than the risk that all tracts are dry. It is illogical for the State to accept the company's perception of risk, because the State's is less. It is to the State's advantage to share in the risks. The bidding system in which the State shares the most risk is the net profit share.

DMEM's rough draft analysis compares revenues from two risk scenarios: a 50 percent chance of finding what you expect is there, and a 10 percent chance. In both cases, net profit share leasing generates more expected revenue than either bonus or royalty bidding. We recommend that DMEM model the 100% case as well.

Conclusion

We compliment DMEM for its rough draft economic analysis; it is an encouraging first step in developing the theoretical framework needed to evaluate leasing systems. In summary, we are anxious to see the following in the final Economic Analysis that DMEM sends DNR:

- (1) The evaluation of the effect of obtaining better geologic data by drilling wells on-structure prior to a lease. This must be evaluated on an expected value basis and in terms of increasing competition.
- (2) The evaluation of split-leasing, which separates the exploration phase from the development phase of oil and gas production. Implicit in this analysis is a reduction of risk to the company that ends up developing the lease.

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- (3) The evaluation of the effect of withholding certain highly prospective tracts within the sale area, and tracts where competition may be reduced because of unavailable confidential data.
- (4) A comparison of all scenarios at 100 percent chance of success, to evaluate each system simply in terms of its efficiency in collecting rent.

~~Beaufort Seismic Analysis~~
by Ed Phillips, DMEM

INTRODUCTION

ROUGH DRAFT

Because of perceived inadequacies in the State's oil and gas leasing, the Legislature amended the law in 1978 and again in 1979. These amendments added a variety of net profit and royalty options to the existing law. This study was undertaken to analyze the potential economic tradeoffs to the State from exercising these options, some of which depart significantly from the State's traditional method of leasing potential oil and gas lands (cash bonus plus a minimum royalty of 12.5 percent).

The analysis was performed using an orthodox, oil industry cash flow model designed by Garrett Computing Systems, Inc. of Dallas, Texas. The computer simulations were run under a variety of assumptions concerning field size, oil prices, production costs and risk assumptions.

The basic data on field size and cost (both operating and capital) were gleaned from the Department of Interior's Beaufort Sea EIS. The State's Division of Minerals and Energy Management played a major role in assembling the original data for the EIS and it was felt that these data represented the best available information.

Three general leasing systems are directly compared: Traditional (cash bonus plus minimum royalty), Royalty, and Net Profit Shares.

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A compromise system involving a sliding-scale royalty is analyzed separately. The leasing systems are evaluated in terms of their ability to transfer economic rent to the state as well as the timing of the potential revenues that the state would receive from leasing its potential oil and gas lands.

The systems are also evaluated in terms of their potential ability to encourage economically efficient resource use. For example, a system may generate substantial revenues to the state but discourage the development of marginal fields and encourage abandonment of producing fields before all of the economically recoverable oil is recovered. Other things being equal, it is desirable that all economically recoverable oil and gas be extracted in an efficient (cost minimizing) manner.

The systems differ in the way in which income generated from the leasing process is distributed among the participants. This distribution is affected by the risk sharing nature of the arrangements and the level of competition among bidders.

The risks to be shared are of two major types: geologic and commercial. Geologic risk refers to the possibility of oil and gas being discovered in the absence of direct information (drilling). The commercial risk is attendant upon the anticipated costs of development and production as well as possible future prices. Leasing systems that shift the burden of payment from ex ante estimation (cash bonus) to ex post results (royalty,

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net profit share) shift a proportion of the risks from the lessee to the lessor. Lease arrangements that shift the burden of payment from estimates to actual results are referred to as contingency payment systems in that the payments are contingent upon the actual discovery of oil and gas in commercial quantities. Royalty bidding is an example of a contingency payment system. As this study will show, the shifting of these risks dramatically affects the potential income division between lessee and lessor.

Economists often refer to the distribution issue as the division of the economic rent between the resource owner (lessor) and the producer (lessee), rent being viewed as the economic surplus remaining after labor and capital have earned their competitive or opportunity cost returns.

Contingency systems potentially offer the lessee a larger portion of this rent as a direct result of sharing more of the risks inherent in the oil and gas discovery process. This sharing also implies that the lessor's income will vary in response to the quality and quantity of oil discoveries, that is to say, rich, productive fields will yield high incomes and marginal fields very little.

The first section of this study describes the basic leasing systems. The systems are evaluated in terms of how they influence the behavior of the participants. That is, does the system encourage economic efficiency? A potential tradeoff with

any leasing system is between more revenue for the lessor but less ultimate recovery from the field. Theoretically, contingency payment systems offer the lessor more income but at the loss of economically recoverable reserves.

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Following the discussion of the basic systems, the results of the computer simulations are presented. The alternative leasing systems are compared under two sets of price, cost and risk assumptions. These assumptions are applied to four hypothetical fields ranging in size from 500 million barrels recoverable reserves to 4.2 billion barrels..

The sliding scale royalty system proposed by the Department of Interior is examined. This compromise system has royalty rates that vary with the real value of quarterly output up to a maximum rate of 65 percent. The specification of the sliding-scale royalty was developed with North Slope geologic and economic parameters and is therefore roughly comparable to the other systems analyzed.

The final section of the paper summarizes and assesses the tradeoffs among the leasing systems.

DESCRIPTION OF BASIC LEASING SYSTEMS

Cash Bonus Low Royalty (12.5%)

The winning bidder for a tract submits the highest sealed bid. The low royalty means that most of the geological and economic uncertainty (risk) is borne by the lessee and a substantial portion of the lessor's total revenue is based upon the ex ante evaluation of the tract's net present value. The magnitude of the bid is influenced not only by the firm's estimates of potential costs, revenues and reserve size, but by the number of potential bidders for the tract. Other things being equal, the average level of bids will increase with an increase in the number of potential bidders.

ROUGH DRAFT

The cash bonus system with a low royalty is essentially symmetrical with respect to risk sharing. That is to say, the winning bidder absorbs any divergence from his original expectations in the form of profits or losses. The lessor has effectively transferred risk to the lessee.

This traditional leasing system is economically efficient in that virtually all economically recoverable oil will be extracted. Even if the geology is less favorable than originally anticipated, if the rate of return on additional investment is at least equal to the opportunity cost of capital, the field will probably be developed. The cash bonus plays no role in the development decision. The firm stands to capture all but 12.5% of the

anticipated future cash flow. As long as the present value of this cash flow, net of taxes, discounted at the firm's opportunity cost, is at least equal to the incremental field investments required for production, the decision to develop the field will be made. It should be noted that the decision would be the same in the absence of the bonus. It is the low level of contingency payments that leads to the economically efficient decision to develop, not the bonus.

It is also argued that the payment of a large front end bonus will lead to the diligent development of a lease. This is true to the extent that the firm's opportunity cost of capital exceeds the rate at which the value of oil in the ground is growing. If the value of reserves was growing at 15 percent per year in real terms and the firm's opportunity cost of capital was 10 percent, it is not obvious that the bonus would assure "diligence."

ROUGH DRAFT

Finally, from the lessor's viewpoint, the extent to which the bonus transfers the economic rent to the lessor is extremely sensitive to the level of competition. Paradoxically, it is alleged that the traditional cash bonus system hinders competition because of the requirement of a high front end bonus. Smaller firms lack the financial resources to compete effectively in the bidding process and the geological risk is too great to rely on traditional capital markets for the necessary funds.

There are two obvious possibilities for reducing this financial

barrier. Small firms can bid jointly, thereby pooling their financial resources and reducing financial risk. The other possibility entails improving the quality of information available before a sale, and in the extreme case splitting the leasing procedure into a two-stage process and holding a sale for field development after oil had been discovered. Once the geological risk is removed, the reserves become a bankable asset and smaller firms could borrow from traditional sources in the capital market to bid in lease sales. Under these conditions the winning bidder would likely be the most efficient firm.

Royalty Bid - Fixed Cash Bonus

ROUGH DRAFT

Under this system the bidder pays a minimum fee, then pledges a proportion of future gross revenues and/or production. The winning bidder is the one that pledges the largest share of future gross revenues or output to the lessor.

The initial financial payments to the lessor are minimal; hence the front end burden is lessened. Lessor income is now largely dependent upon the discovery of oil and gas in commercial quantities. Making the payment contingent upon discovery and development shifts some of the geological risk to the lessor.

Likewise, some of the economic or commercial risk is also shifted to the lessor. The specification of the royalty in terms of gross revenue means that the lessor is sharing some

of the future price risk. The higher the royalty rate, the more is the price risk shifted to the lessor.

The royalty bid is made ex ante and represents the bidder's best estimates of future prices and costs. In effect, the royalty is an excise tax on future production. Based only on gross revenues, the royalty is insensitive to operating costs associated with production. A 40 percent royalty on a \$10.00 barrel of oil (wellhead) is \$4.00 whether the cost of producing the barrel is \$1.00 or \$9.00. This insensitivity to costs has important implications for the decision to develop fields and how to best develop a particular field or tract.

ROUGH DRAFT

High fixed royalties are not economically efficient. Oil that has a market value of \$10.00 at the wellhead will not be produced with a 40% (or greater) royalty if the variable production costs are in excess of \$6.00. When a field is developed, "high grading" will occur. That is, only the best tracts will be developed, leaving other tracts with valuable oil reserves untouched. The tracts that are developed are developed less intensively than had the royalty been minimal. This happens because the royalty payment directly reduces the expected present value of the future cash flow. The net result is to reduce field investment, lengthen field life and reduce ultimate recovery. The introduction of the high royalty distorts the relationship between the market price and the cost of production, leading to economically inefficient decisions.

Part of this distortion is also related to the asymmetric nature of the risk sharing under high royalties. The lessor shares in the benefits of profitable developments but does not participate fully in the dryhole risk associated with unsuccessful ventures; as a result, the expected value of benefits (from the lessee's view) are reduced while the expected value of costs are unaffected. This asymmetry will, ex ante, reduce the value of all tracts in a lease sale.

Balanced against this economic inefficiency is the likelihood of increased competition under a royalty bidding scheme. Bidder eligibility is greater because the front end cash payment is less. The increased competition will increase the present value of the bids from a lessor's point of view. Over the long run, the possibility does exist that the lessor will gain more income from royalty bidding than from the traditional cash bonus/low royalty alternative. This result clearly obtains if the fields are actually developed.

ROUGH DRAFT

This qualification is important, as the speculative holding of leased tracts could be a problem with royalty bidding. High and/or higher bids involve few resources at the time of sale; hence a bidder that holds an extreme view of the likely state of nature can express that view with little immediate sacrifice. A 70 percent royalty bid involves the same out-of-pocket cost as a 60 percent royalty bid but has a greater chance of winning the auction. There is nothing in the logic of royalty bidding to prevent a tract from repeatedly being sold at uneconomic royalty rates.

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When production commences, revenues minus operating expenses, state taxes and/or royalties are credited against the investment account. No profit share payments are due until the account balance is zero. At this time the firm has recovered its investments as well as earning a stipulated interest rate. The lessor (State) now begins to receive the profit share that was bid or stipulated at the time of the lease sale. The investment account would be re-opened whenever the firm invests in field facilities or makes secondary recovery expenditures. Profit share payments would be reduced or eliminated until the additional investments were recovered.

ROUGH DRAFT

The advantage of a net profits system could include the enhancement of competition among bidders, improving the ability of the lessor to capture a larger portion of the economic rent of valuable hydrocarbon deposits, and moderating the decline in revenues to the lessor late in field life. Because this system considers both costs and revenues it is economically more efficient than a royalty system that would raise the equivalent revenue.

Provided that costs and revenues are appropriately defined, this system is much less likely to distort behavior in the same sense as high fixed royalties. A portion of the geological risk is shared as payments only occur on profitable discoveries. Both cost and price uncertainty are shared with the lessee, thus the excise tax effect present in the royalty system is absent.

The speculative problem can be resolved by requiring large fixed bonuses, but this solution reduces the attractiveness of royalty bidding as a means of enhancing competition. On balance, it appears that high royalties are a less than optimal mechanism to increase competition for oil and gas leases and increase potential income to the state.

Net Profit Share with Fixed or Variable Cash Bonus

In a general sense, profits are the difference between revenues and costs. In an economic sense, net profits are the return to the firms that allow them to replace their capital. In the state's new leasing regulations, net profits are treated as the return over and above the recovery cost of capital. This form of net profits leasing is called the Investment Account or capital recovery system.

ROUGH DRAFT

Under this system, all capital expenditures (including pre-production as well as post-production expenditures such as secondary recovery investments) are placed in an interest-bearing account. As long as this account has a positive balance it accrues interest. The interest rate on this account represents the earnings on field investment that the lessee would recover before making profit share payments to the state. Ideally, if the state was concerned only with the maximum recovery of its economically recoverable oil and gas resources, the allowed interest rate under the investment account system would represent the industry's opportunity cost of capital.

Therefore, marginal tracts are more likely to be developed than is the case under royalties that would generate comparable revenues. The possibility of extracting all of the economically recoverable oil and gas exists.

However, the net profits system is not without resource efficiency problems. Certainly high profit shares, say in excess of 50%, reduce incentives for efficiency in the firm's operations. At the margin more effort will be expended to save \$0.60 than \$0.30. High marginal tax rates are generally thought to have disincentive effects and there is no reason to suspect that high net profits shares would be immune from this influence.

ROUGH DRAFT

More importantly, the current net profit system shares risks asymmetrically. This is to say, it potentially shifts a large share of the commercial gain to the lessor, but leaves the burden of the dryhole risk with the firm, thereby deflating the expected value of a given field or tract. As a result, not all economically attractive tracts will be developed.

A further problem centers on the difficulty of correctly defining costs and revenues, and the increased administrative burden associated with implementing the system. The fact that net profit systems have not been widely used in the United States may make oil companies uncertain of how the system would be interpreted and administered by the state.

There is a political uncertainty that a net profits system will

clearly reduce. The ability of the legislature to raise taxes ex post of the lease sale will be constrained. State taxes are deductible against the net profit share. Thus, if the legislature increased taxes by \$1.00 and if the profit share was 50%, net profit payments would be reduced by 50 cents.

ROUGH DRAFT

ECONOMIC ANALYSIS

This chapter presents the results of a computer simulation exercise that compares the three basic leasing methods: cash bonus with minimum royalty, royalty bidding and net profit bidding. In all cases the results can be viewed as symmetric. That is, had the royalty or net profit share been specified in advance, the resulting bonus bid would be the same as the fixed bonus with the contingency payments as the bid variable. This is so because once the geologic and economic parameters are specified there is only one value of the variable payment consistent with the fixed payment that will yield a given rate of return.

The following assumptions are used in the base case (750 MM bbls recoverable):

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1. All prices and costs are expressed in 1979 dollars. The wellhead price is assumed to be \$14.00 at the time of the lease sale (1979). This price is escalated at 2.0 percent per year in real terms throughout the life of the field. Alternative cases are examined whereby the real price is held constant. In the base case (750 MM bbls), average operating costs are \$1.90 per barrel. Capital costs are \$2.53 per barrel of recoverable reserves.
2. With the exception of the 500 MM bbl case, a 23-year production profile is used. Production commences

eight years after the lease sale.

3. Firms are assumed to require an 8 percent real rate of return (beyond inflation) on their investment (after federal income taxes). Later, this assumption is relaxed and the leasing systems are compared with the firms requiring real rates of return of 12 and 16 percent.

ROUGH DRAFT

4. Risk aversion is not explicitly modeled. Firms are assumed to be indifferent among certainty equivalent values. Therefore, all bidding systems are evaluated at the same discount rate. State revenues are evaluated at a zero real discount rate. This implies that the state is indifferent as to when it receives its funds and/or the opportunity cost to the state of delaying the receipt of funds is zero. This is obviously a strong assumption, implying that the reinvestment possibilities faced by the state are poor. The oil industry is assumed to have a real discount rate of 8% reflecting the opportunity cost of capital.

The difference in private and public discount rates is extremely important in evaluating the relative attractiveness of the various leasing alternatives from the state's point of view. It means that future dollars are worth more to the state than the industry. The state benefits from an exchange

that sacrifices current income for future income while industry prefers to give up future income to increase its near term positive cash flows or reduce current negative cash flows. It means that both participants in the leasing process can, in essence, exchange cash flows, with the state sacrificing current income for potential future income. While the industry sacrifices potential future income (relatively low valued) for much smaller current negative cash flows (bonuses).

Had risk aversion been explicitly modeled, the variation in revenue among the basic leasing systems would have been more pronounced. The traditional bonus bid/minimum royalty system would have generated less revenue, as the potential exposure of large amounts of capital for the chance at uncertain prospects would have led to further risk discounting. Explicit recognition of risk would also have led to more divergence between the royalty and net profit systems, because the net profit system shares cost uncertainty as well as price uncertainty.

ROUGH DRAFT

5. Net profits system only allows for capital recovery with no implicit real interest earnings.

Tables I through V summarize the results for four field sizes, two risk probabilities and three basic leasing systems. All none-

tary values are in 1979 dollars and represent total income generated under each leasing system. Under all systems there is a minimum of 12.5 percent royalty, 10.8 percent severance tax and a 9.4 percent state income tax. Thus, the variation in income among the systems is related to the characteristics specific to the system.

In all cases the royalty and profit share systems generate a higher expected present value of revenue to the state than the traditional leasing method. The key concept to understanding these results is expected value. This suggests that the results are the weighted average of a large number of independent trials. Thus, the results are the average revenue streams per trial that would be realized over a series of repeated trials.

Does the repeated trial aspect of expected value vitiate its use where each choice has a different set of economic parameters and geological risks? The answer is no. The expected value concept can be applied to leasing decisions if it is applied consistently to all decisions. To quote a respected authority in petroleum risk analysis:

ROUGH DRAFT

If the decision maker consistently selected the alternative having the highest positive expected monetary value his total net gain from all decisions will be higher than his gain realized from any alternative strategy for selecting decisions under uncertainty. This statement is true even though each specific decision is a

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③ rest of quote

The net profits system adopted by the state, because it allows for the capital recovery of additional field investment, is much more likely to encourage secondary recovery efforts.

The traditional method of leasing with a minimum royalty is also encouraging of secondary investment as the firm can capture most of the financial gain from the effort. The traditional leasing method clearly encourages economic efficiency; the only issue is how the rewards of efficiency are distributed among the participants of the leasing process.

ROUGH DRAFT

If the rate of return assumption is relaxed and the required rate of return is permitted to increase to 16 percent, the revenue generated by all systems declines. Raising the opportunity cost of capital lowers the economic rent generated by the natural resource. After all, rent is defined as the earnings in excess of opportunity costs. Increasing the opportunity costs of the variable resources reduces the rent generating capacity of the natural resource.

Of the basic leasing methods, the traditional method suffers the greatest relative decline. As Table V demonstrates, the expected revenues from the traditional method fall by 22.6 percent. The concomitant declines for the royalty and profit systems are 14.1 percent and 10.6 percent. In other words, the relative performance of the contingency payment systems improves as the industry's required rates of return increase.

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This result must obtain from the relative importance of the

bonus in the total revenue stream received by the state from the traditional leasing system. The bonus falls from approximately \$1.16 billion to \$269 million, or by almost 77 percent. While the relative decline in the bonus is the same for the contingency systems it only represents a loss of \$177.2 million.

At the higher discount rate the bonus as a share of total income declines from 31.4 percent to 9.4 percent in the traditional case, and from 3.3 percent to one percent or less in the contingency cases. The equilibrium royalty share falls from 62.85 to 51.90. The corresponding net profit share falls from 77.1 to 65.9 percent. Most of the decline in total payments is the result of the lower equilibrium contingency shares.

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The results displayed in Tables I through VI are a function of the parameters built into the model. Table VII illustrates the effect of doubling the operating costs over the life of the field. Average operating costs increase to \$3.80 per barrel and exceed \$10.00 near the end of field life. Even though the contingency systems show a greater response to this cost increase, the results are hardly dramatic with the profit share income showing the greatest decline, 10.8 percent.

The reason for the apparent insensitivity of the systems to cost increases is the price/cost assumptions built into the model. The two percent per year increase in the real price of oil moderates the impact of the cost increase. Later, the price

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cost relationship will be altered and the effect will be shown to be significant.

If the real price of oil is assumed to remain constant at \$14.00 a barrel throughout the period of analysis, the resulting revenues to the state are sharply deflated regardless of the leasing method. The revenue totals in Table VIII are about 46 percent of their counterparts in Table V. Relatively, the incomes from the contingency systems fall slightly more. Even so, under the constant price assumption the contingency systems generate about 70 percent more potential income than the traditional system.

ROUGH DRAFT

At the 16 percent required rate of return the net profits system performs relatively better than either royalty or traditional systems. A doubling of the required rate of return only reduces the potential income to the state by 14.6 percent. Income from the traditional method is reduced by over 20 percent. Much of this reduction can be attributed to the reduced bonus as a doubling of the required rate of return reduces the bonus by almost 79 percent. The reduction in the bonus of \$477.7 million is more than the total reduction in state revenues. State revenues only fall by \$432.8 million. The difference, \$44.9 million, is from increased state income taxes resulting from the reduced bonus write off.

Table IX combines high operating costs with the constant price assumption. This case would be regarded as "realistic" by the

industry and "outrageous" by AKPIRG. Compared to the optimistic base case illustrated in Table II, the resulting income flows are severely depressed. The traditional method yields a bonus reduced by 62.7 percent and total revenues are down by 48 percent from \$3.68 billion to \$1.91 billion. The concomitant declines in income from the royalty and net profit systems are 57.1 percent and 56.3 percent.

Where the assumed rate of return is 8 percent, the equilibrium royalty bid of 40.70 percent results in a loss of 24.5 million barrels of reserves. The net profit bid still generates a full recovery of the economically recoverable reserves. Under the 16 percent rate of return assumption no reserves are left in the ground, as the royalty bid is only 28.2 percent.

ROUGH DRAFT

Tables VIII and IX provide an indication of the impact of the cost assumption on the revenues generated by the various leasing systems. The only difference in the two cases is the difference in operating costs. These costs are doubled in the high cost case. This cost change appears to affect revenues from the contingency systems more than the traditional cash bonus system. Traditional revenues fall by 11 percent when operating costs are doubled. Income from the net profit system falls 19.7 percent. The royalty decline is 20.6 percent. Note, if the royalty bid had been made on the basis of the cost estimates in the Low Cost Case, but the higher costs were realized, 60.25 million barrels of economically recoverable reserves would have been left in the ground.

When the required rate of return is increased to 16 percent, the equilibrium royalty rate is sufficiently suppressed so that all oil is recovered. A higher bonus or other investment cost would achieve a similar effect. This result indicates that the state could minimize the loss of recoverable reserves by setting the initial bonus high enough so that the equilibrium royalty rate (given an 8 percent ROR) is low enough to ensure complete recovery. This would entail the loss of some expected revenue.

Tables X and XI along with the accompanying graph illustrate the relationship between the royalty and the rate of return under the different operating cost assumptions. The difference becomes important after royalties reach 20 percent. This explains why the Traditional method was relatively insensitive to the operating cost assumption. The doubling of operating costs exerts only a modest influence on the rate of return until late in field life and these returns are weighted relatively low owing to the discounting process.

ROUGH DRAFT

The leasing systems under investigation have different time profiles of income to the state. The Traditional system yields over 30 percent of its income immediately and the remainder over the life of the field. The contingency systems generate only slightly more than 3 percent of their total revenues immediately and over 96 percent over the productive life of the field, but there is an average 8-year delay before production-related revenues commence. This suggests that the ranking of the systems in terms of the present value of the revenues is sensitive to the rate of interest.

Some might argue that assuming a zero real rate of interest to value state revenues biases the resulting ranking of the systems in favor of the contingency systems. Tables XII through XIV with their accompanying graphs present the present value of income from the various leasing systems at different real rates of interest. The only difference among the tables is the assumed required rate of return. As the required rate of return increase, the real interest rate that equates the present value of the various leasing methods increases. This occurs because the higher earnings requirement is reflected in the discounting of future net revenues and consequently deflates the bonus.

ROUGH DRAFT

The most favorable assumption for the Traditional system is that the industry requires a relatively low real rate of return. Where the industry earns 8 percent the present value of income among the systems is approximately equal at a 10 percent real interest rate. When the required rate reaches 16 percent, the real interest rate that equates the present value of the various systems approaches 20 percent.

The generally high real interest rates required to equate the present value of the various income streams suggests that the state can gain by utilizing contingency systems. One has to argue that the state's opportunity losses are at least 10 percent in real terms before shifting to the Traditional is justified on a present value basis.

This analysis was done under the assumption that firms are risk neutral. Explicit recognition of "risk averse" behavior on the part of firms would have improved the performance of the contingency systems relative to the Traditional. All of the cases examined in this paper suggest that risk shifting is advantageous to the state. This does not imply that the state is risk neutral, which it certainly is not, but that the potential gains from risk bearing are significant.

ROUGH DRAFT

TABLE I

REVENUE TO STATE*

ROUGH DRAFT

FIELD SIZE 500 MM = MILLION BBLs.
 PROBABILITY OF SUCCESS: 50%

	Total Revenue (10 ⁶)	Bonus (10 ⁶)	Royalty or Profit Share %	Bonus %
<u>Leasing Method:</u>				
Traditional	\$2,482.34	\$779	12.5	31.4
Royalty	4,493.88	155.8	62.30	3.5
NPS	4,626.23	155.8	75.55	3.4

FIELD SIZE 500 MM BBLs.
 PROBABILITY OF SUCCESS: 10%

	Total Revenue (10 ⁶)	Bonus (10 ⁶)	Royalty or Profit Share %	Bonus %
<u>Leasing Method:</u>				
Traditional	\$514.00	\$177.0	12.5	34.4
Royalty	888.49	35.40	61.0	4.0
NPS	915.15	35.40	73.70	3.9

* Price: \$14.00 + 2.0% per year
 Firms earn 8% ROR

TABLE II

REVENUE TO STATE*

ROUGH DRAFT

FIELD SIZE 750 MM = MILLION BBLs.
 PROBABILITY OF SUCCESS: 50%

	Total Revenue (10 ⁶)	Bonus (10 ⁶)	Royalty or Profit Share %	Bonus %
<u>Leasing Method:</u>				
Traditional	\$3,682.51	\$1,155.0	12.5	31.4
Royalty	6,721.64	231.0	62.85	3.4
NPS	6,923.6	231.0	77.10	3.3

FIELD SIZE 750 MM BBLs.
 PROBABILITY OF SUCCESS: 10%

	Total Revenue (10 ⁶)	Bonus (10 ⁶)	Royalty or Profit Share %	Bonus %
<u>Leasing Method:</u>				
Traditional	\$735.33	\$252.0	12.5	33.5
Royalty	1,295.91	50.40	59.6	3.9
NPS	1,333.98	50.40	72.1	3.8

* Price: \$14.00 + 2.0% per year
 Firms earn 8% ROR
 Average operating cost: \$1.90 per bbl.

TABLE III

REVENUE TO STATE*

ROUGH DRAFT

FIELD SIZE 150 MMM = BILLION BBLs.

PROBABILITY OF SUCCESS: 50%

	Total Revenue (10 ⁶)	Bonus (10 ⁶)	Royalty or Profit Share %	Bonus %
<u>Leasing Method:</u>				
Traditional	\$ 6,154.71	\$2,040.0	12.5	33.0
Royalty	11,106.53	408.0	64.4	3.67
NPS	11,449.00	408.0	81.25	3.56

FIELD SIZE 150 MMM BBLs.
PROBABILITY OF SUCCESS: 10%

	Total Revenue (10 ⁶)	Bonus (10 ⁶)	Royalty or Profit Share %	Bonus %
<u>Leasing Method:</u>				
Traditional	\$1,274.44	\$458.50	12.5	36.0
Royalty	2,195.79	91.70	62.5	4.2
NPS	2,231.75	91.70	75.0	4.1

* Price: \$14.00 + 2.0% per year
Firms earn 8% ROR

TABLE IV

REVENUE TO STATE*

ROUGH DRAFTFIELD SIZE 4.2 BILLION BBLs.
PROBABILITY OF SUCCESS: 50%

	Total Revenue (10 ⁶)	Bonus (10 ⁶)	Royalty or Profit Share %	Bonus %
<u>Leasing Method:</u>				
Traditional	\$19,333.15	\$6,825.0	12.5	35.3
Royalty	36,143.88	1,365.0	70.35	3.8
NPS	36,708.75	1,365.0	78.85	3.7

FIELD SIZE 4.2 BILLION BBLs.
PROBABILITY OF SUCCESS: 10%

	Total Revenue (10 ⁶)	Bonus (10 ⁶)	Royalty or Profit Share %	Bonus %
<u>Leasing Method:</u>				
Traditional	\$4,034.39	\$1,555.0	12.5	38.5
Royalty	7,164.80	311.0	69.1	4.3
NPS	7,272.72	311.0	77.1	4.3

* Price: \$14.00 + 2.0% per year
Firms earn 8% ROR

TABLE V

TOTAL REVENUE TO STATE

MEDIUM CASE* 750 MM BBLs.
DIFFERENT ASSUMPTIONS ABOUT RATE OF RETURN

	Rate of Return:			
	8%	12%	16%	% Change
<u>Leasing Method:</u>				
Traditional	\$3,682.51	\$3,138.91	\$2,850.60	-22.6
Royalty	6,721.64	6,262.78	5,775.08	-14.1
NPS	6,923.60	6,570.57	6,192.46	-10.6

*Average operating cost: \$1.90/bbl

ROUGH DRAFT

TABLE VI

"GAINS" IN POTENTIAL REVENUE (10^6)
 AT DIFFERENT REQUIRED REAL RATES OF RETURN
 PROBABILITY OF SUCCESS: 50%
 750 MM CASE

	Rate of Return:		
	8%	12%	16%
<u>Leasing Method:</u>			
Royalty	\$3,039.13	\$3,123.78	\$2,924.48
NPS	3,241.09	3,431.66	3,278.86

Gains measured as amounts in excess of traditional.

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different drilling prospect with different probabilities and conditional profitabilities. (Newendorp, Paul D., Decision Analysis for Petroleum Exploration, Petroleum Publishing Company, Tulsa, Oklahoma, 1975, p. 67.)

The continued application of expected value maximization over different decision alternatives satisfies the independent trial criterion associated with decision making under uncertainty.

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In the examples in Tables I through IV, the bonus under the contingency payment systems is set at 20 percent of the traditional level. Column 3 of the tables shows the royalty and net profit shares consistent with the arbitrarily selected bonus. In all cases the royalty and net profit share systems generate over 80 percent more expected income to the state than the traditional method and the royalty performs almost as well as the net profits system. The relatively good performance of the royalty is due to the fact that operating costs only rise to a little over \$5.10 at the end of field life, whereas the price of oil is over \$26.00. This price/cost behavior minimizes the distorting effect of the royalty and improves its relative performance.

Clearly, high royalties would discourage secondary recovery investments by severely reducing the discounted positive cash flow associated with the necessary investment expenditures.

TABLE VII

EFFECT OF CHANGE IN OPERATING COST
ON REVENUE TO STATE FROM DIFFERENT LEASING METHODS
FIELD SIZE 750 MM
PROBABILITY OF SUCCESS: 50%

	Case I	Case II	% Change
<u>Leasing Method:</u>			
Traditional	\$3,682.51	\$3,461.11	-6.0
Royalty	6,721.64	6,022.23	-10.4
NPS	6,923.60	6,172.60	-10.8

Price: \$14.00 + 2.0 percent per year

Case I: Average operating cost = \$1.90/bbl

Case II: Average operating cost = \$3.80/bbl

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TABLE VIII

PRICE \$14.00 HELD CONSTANT
 FIELD SIZE 750 MM REGULAR CASE*
 PROBABILITY OF SUCCESS 50%

8% ROR

	Total Revenue (10 ⁶)	Bonus (10 ⁶)	Royalty or Profit Share %
<u>Leasing Method:</u>			
Traditional	\$2,147.27	\$605.00	12.5
Royalty	3,628.92	121.00	52.25
NPS	3,769.18	121.00	74.1

16% ROR

ROUGH DRAFT

	Total Revenue (10 ⁶)	Bonus (10 ⁶)	Royalty or Profit Share %
<u>Leasing Method:</u>			
Traditional	\$1,714.47	\$127.30	12.5
Royalty	2,957.86	25.46	40.15
NPS	3,216.88	25.46	57.35

*Average operating cost: \$1.90/bbl

TABLE IX

TOTAL REVENUE TO STATE

FIELD SIZE 750 MM HIGH COST*
\$14.00 PRICE
PROBABILITY OF SUCCESS: 50%

8% ROR

	Total Revenue (10 ⁶)	Bonus (10 ⁶)	Royalty or Profit Share %
<u>Leasing Method:</u>			
Traditional	\$1,911.80	\$431.00	12.5
Royalty	2,880.27	86.20	40.70**
NPS	3,025.77	86.20	70.25

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16% ROR

	Total Revenue (10 ⁶)	Bonus (10 ⁶)	Royalty or Profit Share %
<u>Leasing Method:</u>			
Traditional	\$1,586.81	\$72.30	12.5
Royalty	2,292.81	14.46	28.2
NPS	2,410.53	14.46	43.15

*Average operating cost: \$3.80/bbl
**Loss of 24.250 MM bbls of recoverable reserves.

TABLE X
ROR VS. ROYALTY

FIELD SIZE 750 MM BBLs.
PROBABILITY OF SUCCESS: 50%
\$50 x 10⁶ BONUS
PRICE: \$14.00

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Royalty	ROR
0	22.65
10	20.81
20	19.09
30	17.04
40	14.29
50	11.02
60	7.03
70	0.84
72	0

Average operating cost: \$1.90/bbl

TABLE XI

ROR VS. ROYALTY

FIELD SIZE 750 MM BBLs.
 PROBABILITY OF SUCCESS: 50%
 $\$50 \times 10^6$ BONUS
 PRICE: \$14.00

ROUGH DRAFT

Royalty	ROR
0	19.67
10	18.11
20	15.53
30	13.14
40	9.44
50	4.80
55	2.27
58	0

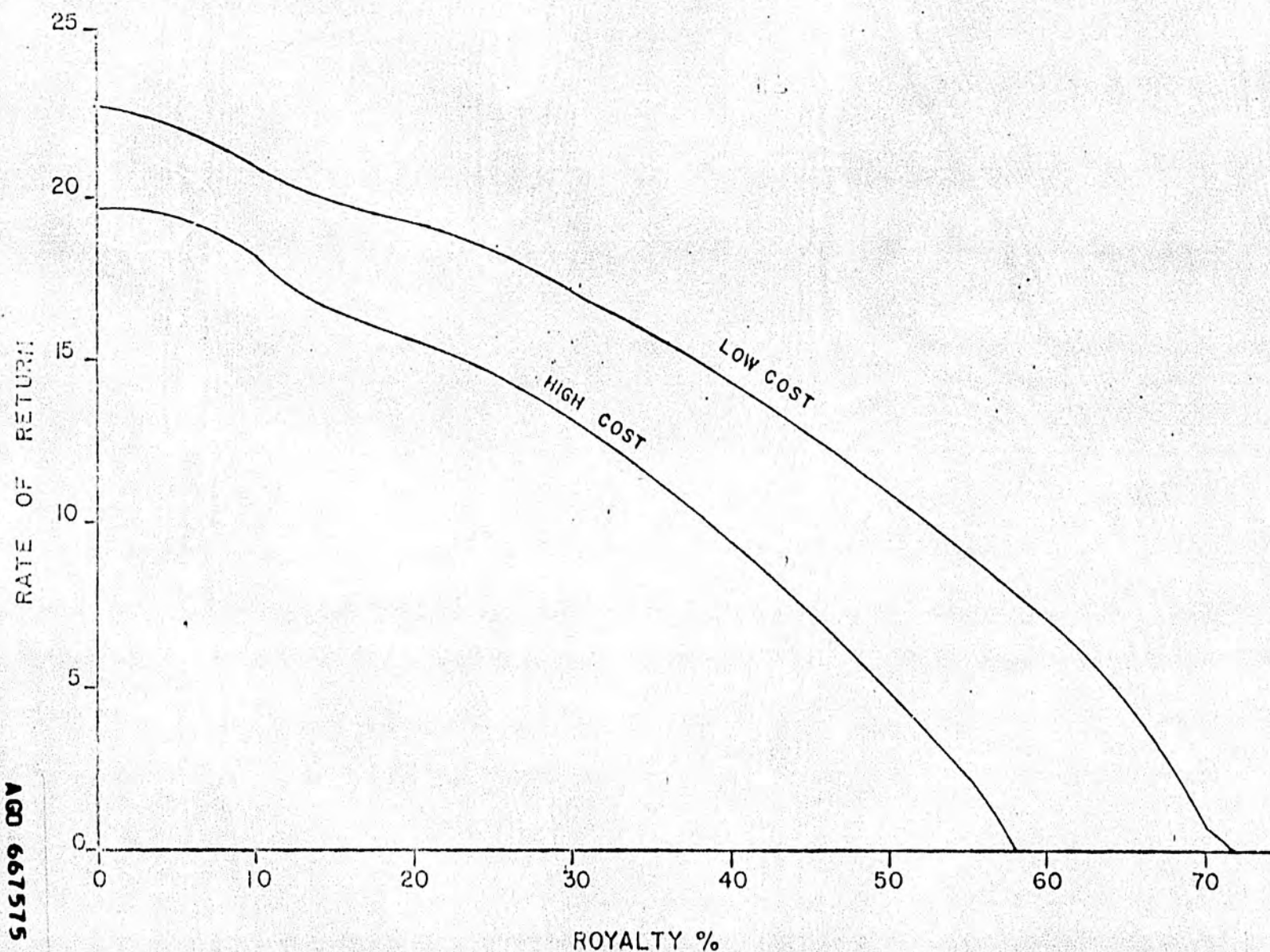
Average operating cost: \$3.80/bbl

ROYALTY VS. RATE OF RETURN

HIGH AND LOW COST

PRICE = 14.00 750 MMBBL

BONUS = 50.00×10^6



HIGH AVERAGE OPERATING COST = 3.80 BBL
LOW AVERAGE OPERATING COST = 1.90 BBL

AGO 667575

TABLE XII

PRESENT VALUE OF INCOME RECEIVED BY STATE
AT VARIOUS REAL RATES OF INTEREST (10^6)

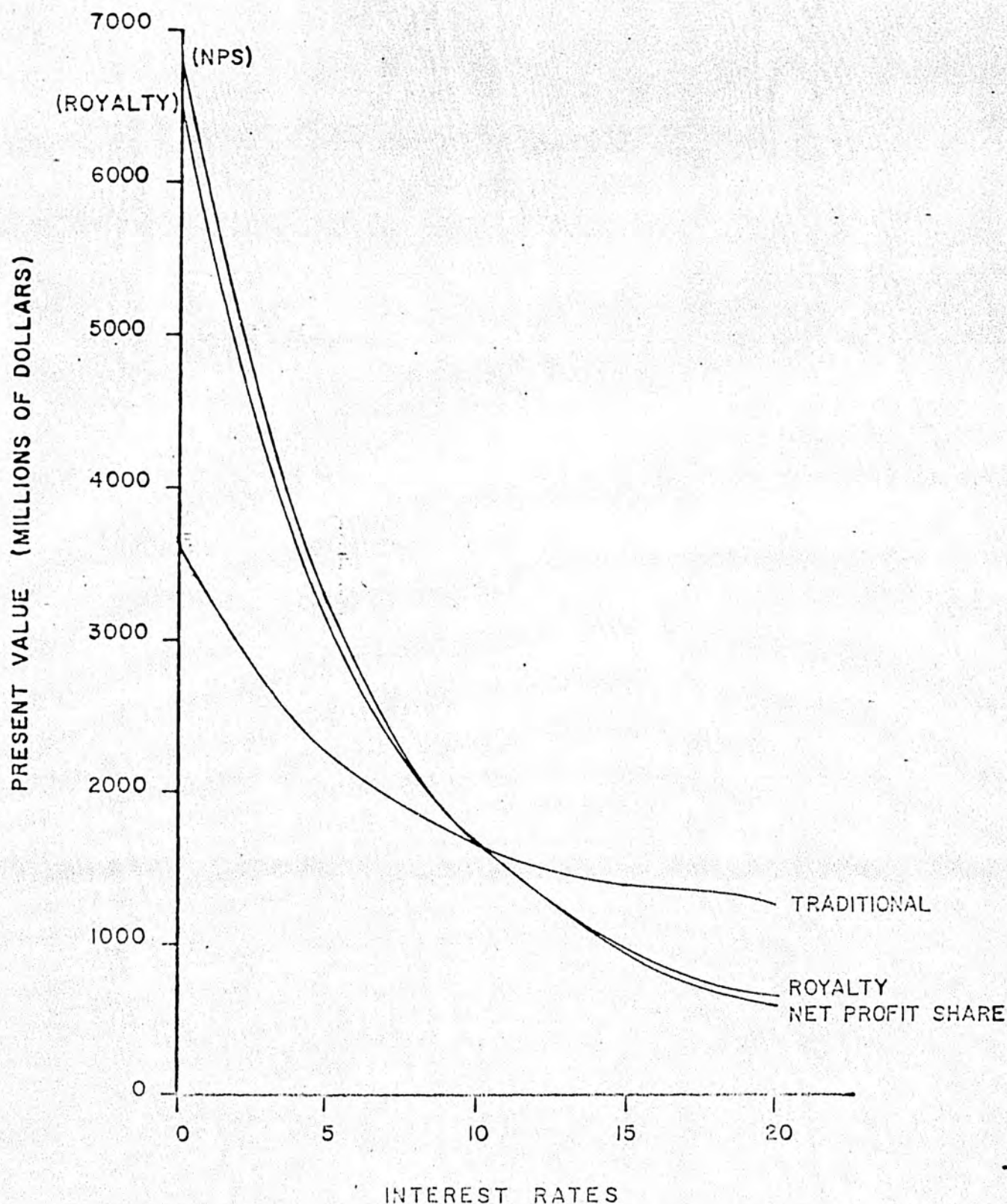
FIELD SIZE 750 MM
PROBABILITY OF SUCCESS: 50%

ROUGH DRAFT

	Traditional	Royalty	NPS
<u>Interest Rates:</u> (Real)			
0	\$3,682.51	\$6,721.16	\$6,923.60
5	2,287.78	3,201.12	3,231.85
10	1,687.83	1,678.89	1,658.94
15	1,411.14	972.67	942.92
20	1,277.42	625.48	598.64

Price: \$14.00 + 2.0% per year
Firms assumed to earn 8% ROR
All cases have royalty & severance tax

PRESENT VALUE OF INCOME RECEIVED BY THE STATE
AT VARIOUS REAL INTEREST RATES (10^6)
750 MM FIELD 50% CHANCE OF SUCCESS



FIRMS ASSUMED TO EARN 8% RATE OF RETURN

AGO 667577

TABLE XIII

PRESENT VALUE OF INCOME RECEIVED BY STATE
AT VARIOUS REAL RATES OF INTEREST (10^6)

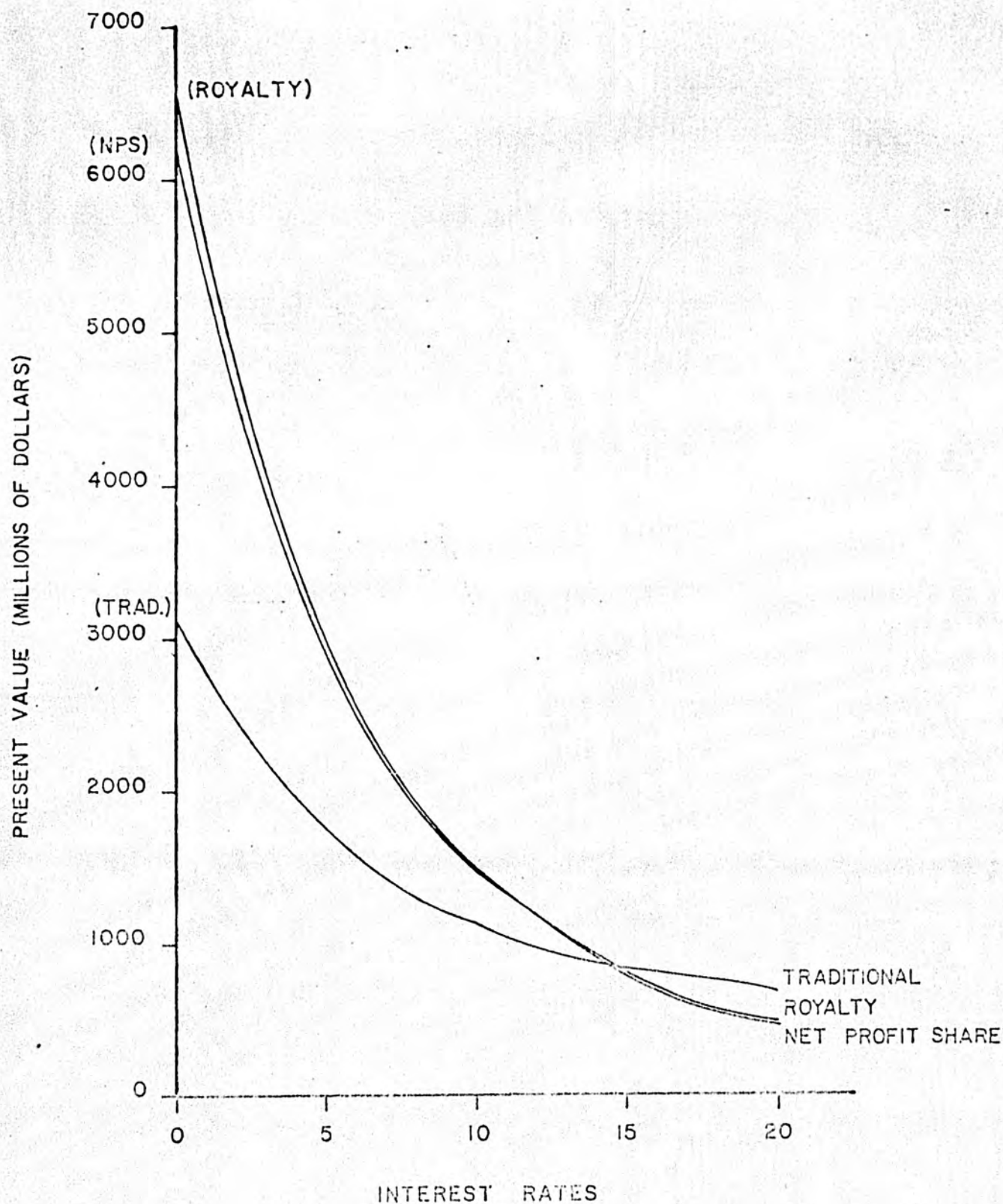
FIELD SIZE 750 MM
PROBABILITY OF SUCCESS: 50%

	Traditional	Royalty	NPS
<u>Interest Rates:</u> (Real)			
0	\$3,138.91	\$6,199.78	\$6,536.64
5	1,725.60	2,898.16	2,990.24
10	1,115.60	1,470.32	1,480.00
15	833.82	807.90	793.07
20	696.32	482.18	463.13

Firms assumed to earn 12% ROR

ROUGH DRAFT

PRESENT VALUE OF INCOME RECEIVED BY THE STATE
 AT VARIOUS REAL INTEREST RATES (10^6)
 750 MM FIELD 50% CHANCE OF SUCCESS



FIRMS ASSUMED TO EARN 12% RATE OF RETURN

AGO 667579

TABLE XIV

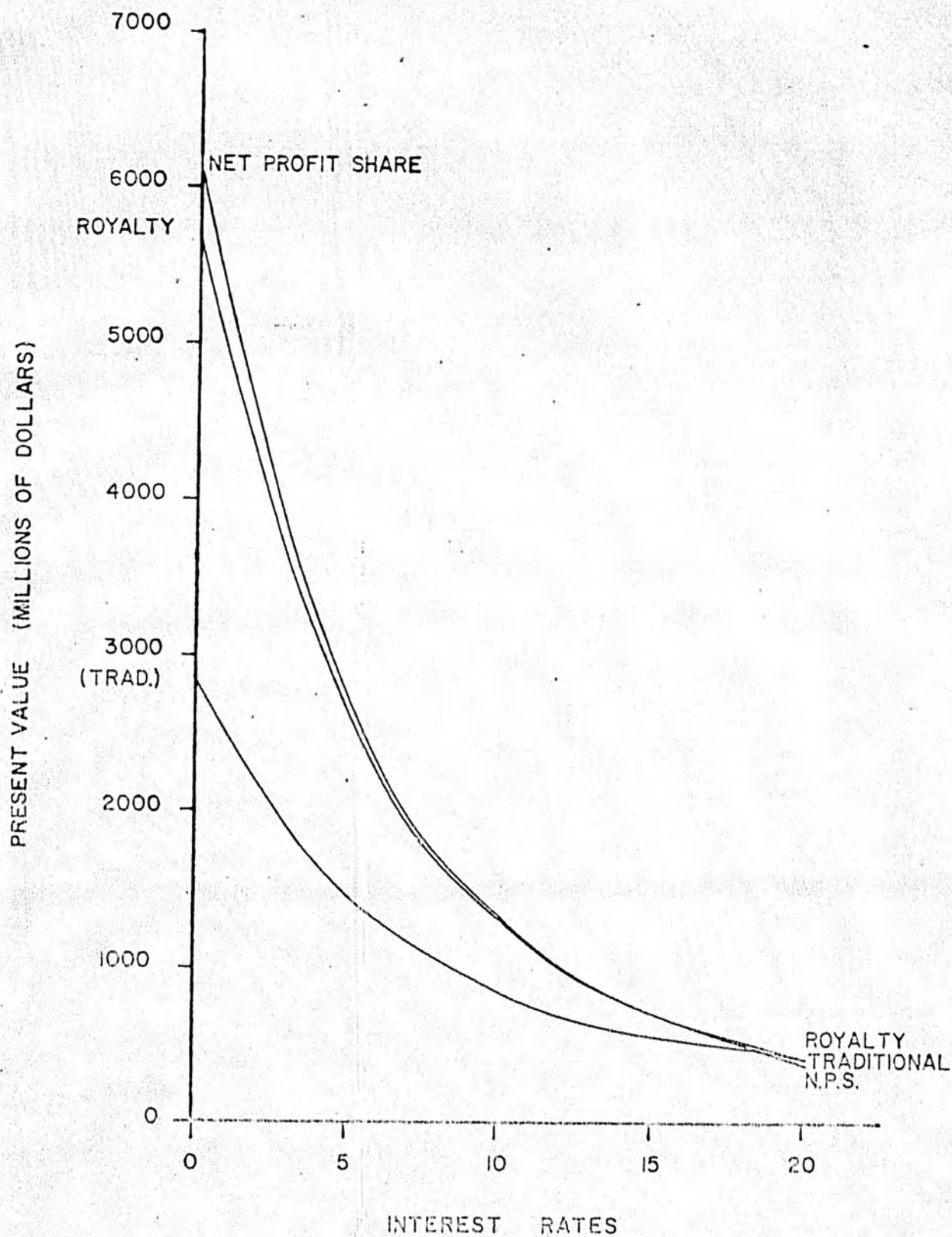
PRESENT VALUE OF INCOME RECEIVED BY STATE
AT VARIOUS REAL RATES OF INTEREST (10^6)FIELD SIZE 750 MM
PROBABILITY OF SUCCESS: 50%

	Traditional	Royalty	NPS
Interest Rates: (Real)			
0	\$2,879.80	\$5,717.00	\$6,160.46
5	1,457.63	2,646.90	2,793.19
10	843.10	1,319.03	1,358.28
15	558.62	702.91	705.04
20	419.33	399.91	309.93

Firms assumed to earn 16% ROR

ROUGH DRAFT

PRESENT VALUE OF INCOME RECEIVED BY THE STATE
AT VARIOUS REAL INTEREST RATES (10^6)
750 MM FIELD 50% CHANCE OF SUCCESS



FIRMS ASSUMED TO EARN 16% RATE OF RETURN

AGO 667581

STATE OF ALASKA

DEPARTMENT OF NATURAL RESOURCES

MINERALS AND ENERGY MANAGEMENT

JAY S. HAMMOND, GOVERNOR

703 W. NORTHERN LIGHTS BLVD.
ANCHORAGE, ALASKA 99503

July 23, 1979

Rep. Joe McKinnon, Chairman
Interim Committee on Oil & Gas Leasing Policy
Alaska House of Representatives
727 N Street, Suite 2
Anchorage, AK 99501

Dear Rep. McKinnon:

In a letter of July 12 from Bob Williams of your staff, you asked for clarification regarding the state's position on certain matters related to the Beaufort Sea lease sale.

The state is not now committed, nor will it be on August 1, to the selection of a particular bidding system for leasing the disputed acreage. At the request of the Department of Natural Resources and the state members of the Task Force, the federal government has agreed not to include the selection of a bidding system for disputed/federal acreage in the Proposed Notice of Sale, which is scheduled for publication August 16. However, the selection of a bidding system for the disputed acreage must be made no later than late October. The earlier the bidding systems are determined, the better.

The department's pre-sale economic analysis of the bidding systems currently authorized by state law should be completed by mid-August. We will not make a commitment to a bidding system for the disputed acreage until this analysis is complete. It is our intention to make the substance of the pre-sale analysis public after it is completed and reviewed by the Commissioner and the Governor. However, certain specifics of the methodology for determining bid acceptance/rejection must be held on a confidential basis. The analysis will demonstrate why a particular system or systems may be better than other alternatives.

The state is not committed, at this time, to using the same bidding system on each structure. There are many valid reasons why the state and federal governments should consider using the same bidding system on structures or prospects which overlap state, federal or disputed acreage. For such reasons, the Task Force may formally recommend that identifiable structures (or prospects) be leased under a common system.

Rep. Joe McKinnon
Page Two

The differences between the state and federal procedures regarding post-sale bid acceptance or rejection have not yet been resolved, but the Task Force will draft criteria and guidelines for the acceptance or rejection of bids on disputed tracts. This joint recommendation to the Governor and the Secretary will be presented as a Task Force recommendation during the week of August 6. This recommendation will be confidential, since it must not be made known to prospective bidders.

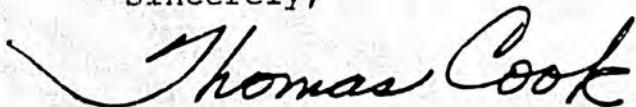
Task Force members from the USGS and DMEM have been negotiating with oil industry representatives for some time in an effort to work out a way in which confidential well data (presently in the possession of the state) can be made available to the USGS. We are optimistic that such well data will be made available to the USGS when we have worked out an agreement which safeguards the proprietary nature of the data. Several companies have agreed in principle to release the well data to the USGS. Seismic data in the custody of DMEM and USGS are being shared presently; the exchange of the seismic data is subject to the conditions of several letters of agreement which have previously been made available to the Legislature.

I have enclosed for your information a timetable of the remaining administrative tasks to be accomplished before the December sale date target.

You also inquired regarding the scheduling of future Task Force meetings. Such meetings are held as needed, often on very short notice. Presently, the Task Force has scheduled a meeting for Wednesday, 9:00 a.m. at the OCS office. This meeting is for the purpose of discussing the draft stipulations and mitigating measures. No other meetings have been set at this time.

I will be happy to discuss these points in more detail, as well as any other matters about which you may have questions, at the informal briefing now scheduled for Thursday, July 26.

Sincerely,



Thomas Cook
Director

Enclosure

cc: Robert E. LeResche, Commissioner
Jeff Haynes, Deputy Commissioner
Jeff Lowenfels, Assistant Attorney General
John Miller, Petroleum Manager, DMEM

AGO 667583

BEAUFORT SEA SALE TASKS

<u>BEAUFORT SEA SALE TASKS</u>	<u>COMPLETION DATE</u>	<u>RESPONSIBILITY</u>
Select a net profits bidding system.	7/18/79	DMEM/DNR
Environmental Impact Statement (EIS) circulated for agency review.	7/18/79	Task Force
29/74 meeting on environmental stipulations in Washington, D.C.	7/18/79	DOI/DOE
Complete recommendations for Secretarial Issues Document (SID).	7/27/79	Task Force
Complete final drafts of regulations on net profits, sliding royalty and royalty bidding, work commitments and exploration incentive credit.	7/31/79	DMEM/Law/DNR
Complete testing of economic models.	7/31/79	DMEM/USGS
Give notice of regulations on net profits, sliding royalty and royalty bidding, work commitments and exploration incentive credit.	8/1/79	DMEM/Law/DNR
Send "Proposed Notice of Sale" on disputed/federal lands to Washington, D.C., for review.	8/1/79	Task Force
EIS to printer.	8/2/79	Task Force
Send final SID to Washington for review.	8/6/79	Task Force
EIS released.	8/10/79	Task Force

Interim Legal Agreement completed.	8/13/79	Task Force/Law/DMEM/DNR
Interior Secretary approves Proposed Sale Notice.	8/13/79	Interior Secretary
Second Notice of regulations on net profits, sliding royalty and royalty bidding, work commitments and exploration incentive credit.	8/15/79	DMEM/Law
Proposed Notice of Sale published for disputed and federal lands.	8/16/79	DOI
Economic pre-sale analysis of bidding alternatives completed.	8/16/79	DMEM
Complete revisions of lease document.	8/27/79	DMEM/Law
Complete geologic model.	8/31/79	USGS
Hearing on net profits, sliding royalty and royalty bidding, work commitments and exploration incentive credit regulations.	9/4-7/79	DMEM
Hearing record on regulations closes.	9/19/79	DMEM
Regulations to Lieutenant Governor.	10/5/79	DMEM/Law
State Notice of Sale under AS 38.05.305 (traditional uses).	10/1/79	DMEM/Law/DNR
State Notice of Sale under AS 38.05.345 (general notice).	10/16 - 11/7	DMEM/Law/DNR
Regulations effective.	11/5/79	
Final Notice of Sale (joint state and federal).	11/9/79	DNR/DOI
Sale.	12/11/79	