ALASKA LEGISLATURE SPECIAL COMMITTEE/SUBJECT FILES 8672

2326 SCOMM 96: HOUSE SPEC. COMM. ON OIL & GAS, 1995-1996

In this analysis, the department selected a low average wellhead value of $12 per barrel and a high average wellhead value of $22. These wellhead values were chosen to represent possible average wellhead values for the entire life of the field. These wellhead values roughly correspond with United States West Coast average prices of $20 and $30 per barrel, respectively.

Assuming first that the average wellhead value for oil produced from the Kuparuk Formation is $12 per barrel and the State's royalty is reduced from 20% to 5%, the State will lose $64,000,000 in royalties on oil produced during the next twenty-two years, and gain $720,000 in royalties on oil produced twenty-two to twenty-five years from now. Total recovery of additional production under a reduced royalty rate is estimated to be 1.2 million barrels of oil valued at $14,400,000.

Assuming that the average wellhead value is $22 per barrel and the State's royalty is reduced from 20% to 5%, the State will lose $109,000,000 in royalties on oil produced during the next twenty-two years, and gain $1,220,000 in royalties on oil produced twenty-two to twenty-five years from now. The total incremental volume of oil that would be achieved through a reduction in this case would be valued at $26,400,000.

Under both scenarios the cost of the royalty reduction to the State is roughly four times the combined value of the benefits, including the state's royalty share. These analyses were conducted in constant 1989 dollars. Obviously, had they been done in present value terms, the disparity between costs and benefits would have been even greater.

But there are other benefits which may be obtained by reducing the royalty rate to 5%. By letters dated May 16 and October 9, 1990, Conoco committed to expand its 3-D seismic program, and, dependent on the outcome of the seismic program, possibly drill two additional wells to evaluate three regions of the Kuparuk Formation within the Milne Point Field. These wells would be targeted to delineate the resource potential of several small fault blocks and/or the down-dip limit of the field. Conoco first termed the magnitude of reserve additions attributable to these operations as "totally speculative." Subsequently, Conoco

provided reserve estimates for one of the three regions and risk factors for all three regions. Based on the relatively low reserve estimate, coupled with the risk factor, the conditional nature of the commitment to drill, and ownership interests of other parties in the reserves, the department concludes that the potential incremental benefits of royalty reduction are insufficient to tip the scales in favor of granting the reduction requested.

Based on the extraordinary value of lost royalties, the modest benefit of a 1.2 million barrel increase in production, and the highly speculative benefits of Conoco's commitment to additional exploration and development activities, it is extremely difficult to make a finding that granting the royalty reduction which Conoco requests is either necessary or proper to secure the proper protection of the public interest.

VII. Evaluation of Application Under AS 38.05.180(j), Prior to Amendment By HB 128 in 1990

AS 38.05.180(j), as it existed at the time the Milne Point Unit Agreement was executed and at the time Conoco's application was submitted, stated:

> **AS 38.05.180(j) "To prolong the economic life of an oil and gas field,** the commissioner shall adopt regulations for all bidding methods to allow reduction of royalty on leases within the field **to compensate for increasing costs in the later stages of production decline. The commissioner may not grant a reduction** of royalty until **two years'** initial production from the field has occurred and each **lessee** requesting the **reduction has** made a clear showing that the revenue from all hydrocarbons produced from the field **is insufficient** to produce a reasonable rate of return with respect to that lessee's total investment in the field."

(Emphasis added).

As with AS 38.05.180(p), relief under AS 38.05.180(j) is discretionary. However, the department should not exercise its discretion in favor of royalty reduction unless the reduction is in the public interest. For the reasons discussed in Part VI, above, granting the royalty reduction as requested by Conoco is not in the public interest.

To qualify for relief under AS 38.05.180(j), an applicant must establish that the relief requested: (1) follows two years initial production from the field; (2) will prolong the economic life of the field; (3) will compensate for increasing costs in the later stages of production decline; **and** (4) is necessary to produce a reasonable rate of return on the applicant's total investment in the field.

Conoco submitted its application for royalty reduction immediately following two years of cumulative production from the Kuparuk Formation of the Milne Point field; therefore, the requirement of two years initial production from the field has been met. However, Conoco has not established that the requested royalty reduction will significantly prolong the economic life of the field. While the field life might be extended by three years, more than twenty years in the future, the number of years added is not relevant--the number of additional barrels recovered is. Conoco's unconditional commitment to increased production is limited to 1.2 million barrels. This volume represents less than 2% of the estimated production for the Kuparuk Formation, and an even lesser percentage of estimated production for the Milne Point field. Given the cost to the State of the royalty reduction requested, the amount of potential new production 20+ years hence is almost inconsequential in both absolute and relative terms.

Having failed the second part of a four part test for royalty reduction under AS 38.05.180(j), it is unnecessary to examine elements three and four. However, brief mention of the two remaining elements is appropriate. AS 38.05.180(j) restricts royalty reduction to instances in which it will compensate for increasing costs in the later stages of production decline. First, the department has received no information that would indicate the Milne Point field is in the later stages of production decline. To the contrary, Conoco has announced plans to develop the Schrader Bluff Formation within the Milne Point with the ultimate goal of at least doubling production. Second, the department interprets this requirement as limiting the amount of relief which may be granted to that amount necessary to offset the increase in costs. It is impossible to ascertain whether royalty relief granted after three years of production in a field with an estimated field life of twenty-five to twenty-eight years would compensate for, and be commensurate with, increasing costs in the later stages of production decline. Given the volatility of future oil prices and the remoteness of late-stage costs, the

department should not conclude that this standard would be met by granting the requested royalty reduction at this time.

Finally, AS 38.05.180(j) requires the applicant to make a clear showing that the revenue generated by the field is insufficient to produce a reasonable rate of return on the total investment in the field. A clear showing requires evidence which is precise, explicit, and which directly establishes the point. It is very difficult, if not impossible, to provide such evidence here, since the Milne Point field is in the very early stages of production. Use of estimated value, production, and cost data for the remaining twenty-two to twenty-five year life of the field adds a high level of uncertainty to determining the long-term validity of any purported "need" for Conoco's royalty reduction. Particularly disturbing is the unreliability inherent in estimating the value of oil to be produced over the next twenty-two to twenty-five years. As mentioned earlier, this unreliability is dramatically underscored by the tripling of reported wellhead values from the Milne Point Unit between July and September 1990.

Estimating revenue from future production is further complicated by a lack of knowledge regarding the potential volume and value of future production from other pools in the Milne Point field, such as the Schrader Bluff Formation, as well as by price and technology sensitive enhanced oil recovery techniques which may significantly increase total production from all reservoirs or pools within the Milne Point field.

On the other hand, since much of the major field facility development has already occurred, the cost estimates for the remaining field life are easier to approximate. According to the data submitted by Conoco on June 13, 1990, about 87% of the capital investment in field facilities has been completed, leaving only relatively minor capital investment expenses to be estimated. This, however, does not include the costs associated with Schrader Bluff development and production.

In short, the department may reasonably conclude it impossible to make a clear showing that the revenue generated by the Milne Point field over its entire life will be insufficient to produce a reasonable rate of return on the total investment in the field when but a small fraction of the minimum estimated field life has transpired.

In conclusion, Conoco's application should not be granted as requested under AS 38.05.180(j) (as it existed before amended by HB 128). Conoco has not established that reducing the royalty rate on the Kuparuk Formation from 20% to 5% would significantly prolong the life of the Milne Point field. A minimal extension of the field at a very high cost to the State is not in the public interest. Furthermore, the uncertainties inherent in estimating revenue and costs for the next twenty-two to twenty-five years allow the commissioner to conclude that Conoco cannot adequately show either the magnitude of increasing costs in the later stages of production decline or total field life rate of return.

VIII. Evaluation of Application Under AS 38.05.180(j), As Amended By HB 128 in 1990

AS 38.05.180(j) was amended by HB 128, effective September 12, 1990. It now reads:

> **To prolong the economic life of an oil and gas field or to reestablish commercial production of shut-in oil or gas that would not otherwise be economically feasible,** the commissioner shall adopt regulations to allow reduction of royalty on leases. The commissioner may not grant a reduction of royalty unless the lessee requesting the reduction makes a clear showing that the revenue from the lessee's share of all hydrocarbons produced from the field is and is likely to continue to be insufficient to produce a reasonable rate of return with respect to the lessee's total investment in the field. The commissioner may condition a royalty reduction granted under this subsection in any way to protect the state's interest, including restoration of the state's royalty share in the event of an increase in the price of oil or gas. Before approving a royalty reduction, the commissioner shall make a written finding that the state **has obtained the maximum possible economic return that is compatible with allowing a reasonable rate of economic return for the lessee,** and send copies of the finding to all members of the legislature.

(Emphasis added).

As with AS 38.05.180(p), and AS 38.05.180(j) prior to its amendment by HB 128, relief under the amended standard is discretionary. The department, however, should not exercise its discretion in favor of royalty reduction unless the reduction is demonstrated to be in the public interest. For the reasons discussed in Part VI, above, granting royalty reduction as requested by Conoco, in this instance is not in the public interest.

Under AS 38.05.180(j) as amended by HB 128, royalty relief cannot be granted unless it will either prolong the economic life of an oil and gas field or reestablish commercial production of shut-in oil or gas that would not otherwise be economically feasible. The royalty reduction requested by Conoco will not substantially prolong the economic life of the Kuparuk Formation or Milne Point field for the reasons discussed in Part VII, above. Nor is the Kuparuk Formation shut-in as it was for several months before Conoco submitted its application. Therefore, Conoco's application fails these alternative requirements of AS 38.05.180(j), as amended by HB 128.

As 38.05.180(j), as amended, also retains the requirement of a clear showing that revenue from the field is insufficient to produce a reasonable rate of return on total field investment. The department's analysis of this requirement is the same under both the former AS 38.05.180(j) and its current amended version. (See Part VII, above).

The 1990 amendment to AS 38.05.180(j) specifies that an application for royalty reduction cannot be approved unless the commissioner makes a written finding that the State has obtained the maximum possible economic return that is compatible with allowing a reasonable rate of economic return for the applicant. Due to volatile oil prices, risks inherent in oil and gas production, and uncertain future costs, the department cannot find that the State will obtain its maximum possible economic return without providing for the recapture of foregone royalties in the event a lessee ultimately achieves more than a predetermined reasonable rate of return. However, in this instance the department need not craft a limited or conditional royalty relief, since the royalty relief requested is inappropriate for other reasons, as discussed above.

IX. Milne Point Unit Agreement, Paragraph 18(h)(8)

Conoco argues in its August 27, 1990 supplemental brief that paragraph 18(h)(8) of the Milne Point Unit Agreement governs its application for royalty reduction; and that AS 38.05.180 (p) and (j) apply only to the extent that they are not inconsistent with the unit agreement. Paragraph 18(h)(8) states:

> Reduction of Royalty. After two years' initial production from the field in which the leased area is located has occurred, the State may reduce Lessee's obligations to pay royalty on all of the leased area or on any tract or portion thereof segregated for royalty purposes upon (1) request by Lessee and (2) a clear showing by Lessee that the revenue from all oil, gas and associated substances produced from the field is insufficient to produce a reasonable rate of return with respect to Lessee's total investment in the field.

Conoco's argument that paragraph 18(h)(8) prevails where inconsistent with AS 38.05.180(p) or (j) appears to be based on an incomplete reading of paragraph 1 of the Unit Agreement, which states:

> The Alaska Land Act ... and all valid and pertinent oil and gas statutes and regulations including the oil and gas operating statutes and regulations in effect as of the effective date hereof or hereafter issued thereunder governing drilling and producing operations, not inconsistent with the terms hereof or the laws of the State of Alaska are hereby accepted and made a part of this agreement.

(Emphasis added). Conoco chooses to ignore that all statutes not inconsistent with the laws of the State of Alaska are incorporated by reference in the Unit Agreement. Since the statutes are the laws of the State of Alaska, they cannot be inconsistent with the laws of the State of Alaska (except to the extent that one or more statutes are contrary to the United States or Alaska constitution). Therefore, AS 38.05180(j) and (p) are incorporated by reference in the Unit Agreement, and are thus every bit as much a part of the Unit Agreement as is paragraph 18(h)(8).

In any case, a state agency is without authority to enter into an agreement in conflict with applicable statutes. Thus, even without an explicit incorporation of

Alaska's statutes by reference in Paragraph 1 of the Milne Point Unit Agreement, the statutes control when in conflict with the Unit Agreement.

X. Summary

In this instance, I have recommended that the requested royalty reduction should be denied under AS 38.05.180(p), (j), and (j), as amended by H.B. 128 since the department concludes that Conoco has failed to demonstrate:

(1) that granting the requested royalty relief will be in the public interest;
(2) that reducing the royalty from 20% to 5% will significantly prolong the economic life of the field; and
(3) a clear showing that its revenue from oil, gas, and associated substances produced from the field is insufficient to produce a reasonable rate of return with respect to Conoco's total investment in the field.

The statutes and regulations do not discuss the quantity or quality of data needed to demonstrate a clear showing (though, obviously, "clear showing" is a high standard) that Conoco's revenue from the field is insufficient to produce a reasonable rate of return with respect to its total investment in the field. Similarly, the statutes and regulations do not list precisely the quantity or quality of data needed to demonstrate that the economic life of the field will be significantly prolonged by a royalty reduction. These determinations must be made by the commissioner based on the discretionary power granted by the statutes, department regulations, and the Milne Point Unit Agreement. However, it becomes apparent that, especially in the case of a field such as Milne Point, with only a few years of production history, determining the long term profitability of the field with any certainty is virtually impossible.

In order to thoroughly evaluate Conoco's application, an extensive financial, economic, and technical analysis was completed by the department. While I recommend that the department deny the application, this analysis provides a groundwork for evaluating future royalty reduction requests since this was the first request completely processed by the department.

Even though it is recommended that Conoco's application for a royalty reduction to 5% be denied, the division felt obligated to carefully analyze the data submitted to determine if an alternative approach for royalty reduction could be developed which would meet the statutory requirements. Among the possibilities examined were a sliding scale royalty based on wellhead value, short term relief, relief down to a floor of 12.5% and combinations of these three methodologies. These limited and/or conditional alternatives to a complete denial were determined to be unacceptable since in all cases examined, even ignoring Conoco's failure to make a clear showing, the estimated return to the state and public was substantially less than the estimated revenue lost by the state in forgone royalty. Therefore, even a limited or conditional royalty does not appear to be in the public interest at this time.

ENCLOSURE 4

STATE OF ALASKA

DEPARTMENT OF NATURAL RESOURCES

OFFICE OF THE COMMISSIONER

WALTER J. HICKEL, GOVERNOR

400 WILLOUGHBY AVENUE
JUNEAU, ALASKA 99801-1796
PHONE: (907) 465-2400
FACSIMILE: (907) 586-2754

CERTIFIED MAIL — Return Receipt Requested

April 17, 1991

Mr. Richard E. Foppiano
Oxy USA, Inc.
Box 50250
Midland, TX 79710

Dear Mr. Foppiano:

The review process of the Conoco and Oxy USA applications for royalty reduction from 20 percent to 5 percent on the Milne Point Unit Kuparuk production has concluded. Based on the failure to show any net public benefit, I am denying these applications for royalty reduction.

The extensive records on these applications indicate that the profitability of the Milne Point Unit has not achieved the companies' desired level. However, the State as a royalty owner has no authority or responsibility to guarantee the success or profitability of a lessee's investment decisions.

The State of Alaska has given this marginal oilfield significant help by severance tax relief; a further grant of up to $100 million through royalty relief is not warranted. The State as a royalty owner will not share in the risk of the companies' decisions.

However, there are a couple circumstances in which it may be in the public interest for the royalty owner to reduce its share of the current production to gain a long-term payback benefit.

At some point in an oilfield's later life the production revenue (excluding the royalty barrels) will not be sufficient to cover all the cash costs and operations may cease absent royalty reduction. This is not the current situation in the Milne Point Unit where production revenues from the Kuparuk formation are at the $4-to-5-million per month level compared to operating costs of $1-to-1.5 million per month. This circumstance of reaching the "economic limit" of production operations is projected by the companies to occur in a couple decades and can be considered at that time.

A second circumstance in which a royalty owner may choose to help the producer is to encourage further investment that has a direct net benefit to the state. In this situation, the data does <u>not</u> indicate that increasing profitability through a royalty

Enclosure 4

reduction would result in an incremental prospective investment that could have an incremental direct benefit to the State large enough to offset the royalty loss. While this circumstance may occur in the future, the current submittal asks the State to give up over 5 million barrels of royalty oil for a potential reward replacing only a few percent of that loss.

Sincerely,

Harold C Heinze

Harold C. Heinze
Commissioner

cc: John Tillinghast, Attorney
Birch, Horton, Bittner & Cherot
James Eason, Director
Division of Oil and Gas

DECISION OF THE COMMISSIONER
ON OXY'S APPLICATION FOR ROYALTY REDUCTION

OXY USA, Inc. submitted an application to the State of Alaska Department of Natural Resources (DNR). That application requested that the State's royalty share of oil and gas produced from the Kuparuk River formation underlying four Milne Point leases be reduced from twenty percent to five percent.

OXY's application was analyzed by the staff of the Division of Oil and Gas. Edward Phillips, Petroleum Economist (retired), prepared a confidential economic analysis of the application. Mark Myers, Petroleum Geologist, conducted a public hearing on the application, then prepared a Recommended Decision on OXY's application.

Normally, the Commissioner of the DNR would act on a recommended decision without further input from OXY. However, OXY requested and was granted thirty days in which to comment on the Recommended Decision. OXY's comments consisted of fourteen pages of text, an affidavit, and two confidential exhibits, all of which have now been reviewed by this Commissioner.

As Commissioner, I hereby adopt the Recommended Decision as the final decision of DNR, subject to the additional findings and conclusions set forth in the remainder of this Final Decision.

In this Final Decision I do not undertake to address every alleged fact and argument raised by OXY in its final comments. Much of OXY's final comments consisted of arguments raised by Conoco in its final comments on the hearing officer's recommendation on Conoco's parallel application for royalty reduction. For

that reason, I hereby incorporate by reference my Decision on Conoco's application for royalty reduction; that Decision is also being issued on this date.

One argument unique to OXY's final comments is that I should not consider production from the Schrader Bluff formation of the Milne Point field because OXY has not made a decision to participate in Schrader Bluff development. This argument is wholly unfounded. The Schrader Bluff Participating Area was approved by this department's Division of Oil & Gas on March 29, 1991. Production has commenced from the Schrader Bluff Participating Area. OXY currently has a 2.9% interest in any production from the Schrader Bluff Participating Area. Consequently, income to OXY from Milne Point field formations other than the Kuparuk River formation is anything but speculative.

OXY's final comments also criticize this department for its failure to provide OXY with a copy of the confidential economic analysis of OXY's application. Because OXY did not provide the department with complete economic data, the department was not able to fully analyze OXY's application without resort to confidential economic data provided by the Milne Point Unit operator and OXY's co-lessee--Conoco. Until such time as Conoco authorizes release of the data necessarily relied upon by the department, I have no choice but to keep the economic analysis accompanying the Recommended Decision confidential.

Finally, OXY's comments suggest that two third-party measures of a reasonable rate of return cited by the hearing officer in his Recommended Decision both support an 8% real rate of return. In

fact, only one measure supported an 8% real rate of return; the second measure supported a 3.6% real rate of return. The measure selected by the hearing officer yielded a 6% real rate of return.

Subject to the foregoing, the Recommended Decision on OXY's application for royalty reduction for the Milne Point Unit is hereby adopted as the Final Decision of the Department of Natural Resources.

STATE OF ALASKA, DEPARTMENT OF NATURAL RESOURCES

Dated: 4/22/91

Harold C. Heinze, Commissioner

MEMORANDUM
DEPARTMENT OF NATURAL RESOURCES

State of Alaska
DIVISION OF OIL AND GAS

To: Harold C. Heinze
Commissioner

Date: March 5, 1991

Phone: 762-2182

From: Mark Myers
Petroleum Geologist

Subject: Recommended Decision and Finding for Oxy USA Inc.'s Royalty Reduction Application, Milne Point Field

Under my delegation as the department hearing officer, I am enclosing the recommendation and finding concerning Oxy USA Inc.'s application for a royalty reduction from 20% to 5% for the Milne Point Field.

Similar to Conoco, Oxy has requested thirty days to reply to the Recommended Decision. Please feel free to contact me at your convenience, should you have any questions.

Enclosure

Point Unit. In its application, Oxy requests that the State's royalty interest in its production from the Kuparuk Formation, underlying ADLs 47433, 47434, 47437, and 47438 be reduced from 20% to 5%. Oxy has not requested a royalty reduction for production from the Schrader Bluff Formation, which lies above the Kuparuk Formation throughout much of the Milne Point Unit. Nor, to the department's knowledge, has Oxy proposed that the overriding royalty owners reduce their royalty share of Kuparuk Formation production.

Oxy submitted its formal application for royalty reduction in June 1990. However, the application was not determined to be substantially complete until July 1990. A public hearing on the application was conducted by the department on August 28, 1990. Oxy's application has been evaluated under, alternatively, AS 38.05.180(p), AS 38.05.180(j), as it existed at the time the Milne Point Unit Agreement was executed and at the time Oxy's application was submitted, and AS 38.05.180(j), as amended in 1990 by HB 128, effective September 12, 1990.

Two key terms used in these statutes need to be clearly defined in order to make a royalty reduction determination. These terms are discussed in Parts II, III, and IV. Part III defines "field," as used in the royalty reduction context. Part IV analyzes what constitutes a "reasonable rate of return." Part V specifies why a decision to grant royalty relief is discretionary, not mandatory. Parts VI, VII, and VIII address each of the three statutory provisions listed above, as they apply to Oxy's application. Part IX refutes Oxy's assertion that Paragraph 18(h)(8) of the Milne Point Unit Agreement controls disposition of its application for a royalty reduction. Finally, this document concludes with a brief summary of this finding and recommendation.

II. Definitions

Two key terms used in the statutes need to be clearly defined in order to make a royalty reduction determination. These terms are **reasonable rate of return**, and **field**. Since these terms lack statutory definitions for the purposes of royalty reduction, and since no previous requests for royalty reduction have been granted, although a parallel request by Conoco for royalty reduction at Milne Point is pending, these terms are examined with respect to this application. In its

August 27, 1990 supplemental brief, Oxy attempted to define the terms **reasonable rate of return** and **field** and presented arguments why the department should be bound by these definitions in its review of Oxy's application. The following two sections will explain why, in my opinion, Oxy's proposed definitions are inappropriate and must be rejected. Additionally, these sections will provide alternative definitions of these terms and demonstrate why these definitions are appropriate for royalty reduction analyses.

III. Definition of a Field

AS 38.05.180(j), before and after amendment by H.B. 128, and paragraph 18(h)(8) of the Milne Point Unit Agreement restrict royalty relief to instances in which the "field" would not otherwise produce a reasonable rate of return. AS 38.05.180(j) before amendment also requires that royalty relief prolong "field" life. AS 38.05.180(j) after amendment by H.B. 128 requires that either the relief be necessary to prolong "field" life or restore shut-in production. Neither the royalty reduction statutes or the Unit Agreement define "field."

Oxy, in its supplemental brief submitted on August 27, 1990, stated its belief that, for the purpose of royalty reduction, the Milne Point leases contain two separate oil fields, the Kuparuk River and Schrader Bluff "Fields." It based its argument on the fact that the two oil pools are vertically separated, have different reservoir properties, and will require different production techniques. Additionally, Oxy's brief states that the definition it offers is identical to the definition of "field" used in Texas oil and gas law. Oxy's argument for considering the Schrader Bluff and Kuparuk River oil pools as separate fields is summarized by the following statement: "Geologically distinct fields will also be economically distinct, and therefore of little utility in assessing the economics of each other." (Supplemental Brief of Conoco and Oxy USA Inc. p.25).

To support its interpretation of the definition of "field" Oxy referenced *Wotton v. Bush*, 261 P.2d 256 (Cal. 1953), in which for the purpose of well spacing requirements, an administrative officer of the California Division of Oil and Gas testified that "a field has come to be considered as

to support such a finding in Oxy's case. For the reasons discussed more fully both below, I recommend that you deny Oxy's application on these bases.

The department's analysis of Oxy's application clearly illustrates the need for a policy that limits royalty relief to those instances where sufficient objective factual data, including production revenues and development expenses, are available to establish that the reduction of the state's royalty share will both prolong production and result in benefits which are demonstrably in the state's interest. In addition to maintaining a continuous, though reduced, royalty stream, those benefits could include continued employment or new jobs, additional capital investments in wells and production facilities (to increase the total recovery of oil from the field) and other benefits.

Although Oxy's application fails to make a clear showing of its inability to achieve a reasonable rate of return over time or of being in the state's best interest, my review of its application reconfirmed several concerns common to any application for royalty reduction under the existing statutes, as was pointed out in my recent recommendation concerning Conoco's application for royalty relief. These include defining "reasonable rate of return" consistently and objectively for royalty reduction purposes, and structuring any reduction so as to be effective in achieving the desired results without unduly diminishing the state's royalty interest.

Based upon my analysis and using Oxy's application as an example, I recommend an alternative approach from that advocated by Oxy for setting a reasonable rate of return, and provide documentation to support the use of such a standard.

I. Background and Introduction

Oxy Inc. has applied for a reduction of the State of Alaska's royalty interest in oil and gas production from the Kuparuk River Participating Area of the Milne

RECOMMENDED DECISION OF THE COMMISSIONER OF NATURAL RESOURCES REGARDING THE OXY USA INC. APPLICATION FOR ROYALTY REDUCTION ON ADL 47433, 47434, 47437, AND 47438 (KUPARUK PARTICIPATING AREA: MILNE POINT UNIT).

3/5/91

Finding and Recommendation

Oxy USA Inc. (Oxy) has applied for a reduction of its royalty from 20 percent to five percent on Kuparuk Formation oil produced from the Milne Point Unit. Given the short production history of the field, the information provided in Oxy's application and its public comments on the application fail to: (1) provide a clear showing that its revenue over time will not allow for a reasonable rate of return; (2) demonstrate with any certainty that the requested reduction will significantly prolong the life of the field; or (3) demonstrate that the requested reduction would secure the proper protection of the public interest.

A clear showing of a failure to achieve a pre-determined rate of return over time requires accurate forecasting of oil prices over nearly two decades, as well as a clearer understanding of the potential total production from Milne Point, both with and without royalty reduction, than is currently available. The difficulty of reliably quantifying the latter is demonstrated by the reported decision to proceed shortly with Schrader Bluff Formation oil production with the goal of ultimately tripling average daily oil production from the unit. On its face, it is difficult to argue the need for royalty relief at this time for a field which pays no severance tax, and for which the economics will be dramatically altered in the very near future by the operator's decision to pursue commercial development of these shallow oil sands.

You have the discretion to approve a royalty reduction when it is determined to be in the state's best interest. However, our analysis of the potential benefits which may be gained years hence from the forbearance of substantial state royalties for the next twenty years or so does not appear

that expanded area from the region of initial production to the limits of productivity in all lateral directions; and that within a given field there was no structural connection or drainage to or from other fields." It should also be noted that unlike Milne Point, the fields in the *Wotton* case were geographically (laterally) separated and not at different depths on the same leases. The *Wotton* case dealt with the issue of well spacing requirements. Appropriate well spacing is ideally determined by internal reservoir properties including porosity, permeability, heterogeneity, viscosity of oil, reservoir thickness, reservoir pressure, fluid contacts, and other factors. These properties are certainly unique to each pool and/or reservoir and often vary within the same pool or reservoir. A definition of "field" that is applicable for determining production rates, well spacing, participating areas, internal company development plans, tax credit for enhanced oil recovery, etc. may not be applicable or even appropriate to royalty reduction. This is the case with the definition proposed by Oxy.

Oxy argues that its definition is consistent with that used by industry. However, this argument is not persuasive since there is no consistent use of the term "field" within industry. For example, the Kuparuk River Formation within the Kuparuk River Oil Field consists of two separate reservoir intervals, the A and C sands of different geologic age (Valanginian vs. Hauterivian). Additionally, the sands are vertically separated by a major regional unconformity, were deposited in different depositional settings, and have very different reservoir properties. In spite of these different properties neither industry nor the State differentiates these producing intervals when they refer to the Kuparuk River Oil Field. Furthermore, another state regulatory agency, the Alaska Oil and Gas Conservation Commission (AOGCC), considers the A and C sands of the Kuparuk pool plus the vertically separated West Sak pool (Schrader Bluff Formation) as elements of the Kuparuk River Oil Field.

For the purpose of royalty reduction, the department must define "field" in a matter that: (1) is consistent with the intent of the royalty reduction statutes, regulations, and, to the extent feasible, the Milne Point Unit Agreement; (2) is founded on accepted geologic and engineering principles; (3) can be applied

impartially to all applicants for royalty reduction; and (4) will generally result in reproducible results when applied by different qualified petroleum geologists.

A royalty reduction application under AS 38.05.180(j) must comply with 11 AAC 83.185, which requires the application to:

> ... (2) state location and status of all past and present activities on the lease; (3) include a detailed report of all production during the six months preceding the filing of the application; (4) contain a detailed statement covering the entire life of the lease showing all expenses and costs of operating the lease, including all royalties and overriding royalties and all income from all produced minerals from the lease;

(Emphasis added). This regulation evidences the department's interpretation of "field" as clearly referring to all reservoirs underlying the lease.

This interpretation is consistent with earlier comments in a October 9, 1984 letter to Conoco from Division of Oil and Gas Director Kay Brown in which she stated, "the division has no statutory definition of 'field'..." and listed three possible geologic definitions of "field." "Field may refer (1) to a common source of supply, pool, or reservoir; (2) to multiple reservoirs vertically separated; or (3) to multiple, partially overlapping individual reservoirs...."

Further support for the department's interpretation of "field" comes from the definition of "field" used by AOGCC. While AOGCC's definition of "field" does not govern an application for royalty reduction, it is indicative of a definition accepted by industry in some settings. For the AOGCC, "field" is defined by AS 31.05.170(5), which states:

> "field" means a general area which is underlain or appears to be underlain by at least one pool, and includes the underground reservoir containing oil and gas; and the words "pool" and "field" mean the same thing when only one underground reservoir is involved, but "field" unlike "pool" may relate to two or more pools...

For the purpose of royalty reduction requests, the department defines "field" as encompassing the lateral limits of productivity of all reservoirs or pools within the Milne Point Unit regardless of vertical stratification of reservoirs or pools underlying a lease or leases. This definition meets the standards set out earlier; (1) It is consistent with the intent of the royalty reduction statutes, regulations, and to the extent feasible, the Milne Point Unit agreement; (2) it is founded on accepted geologic and engineering principles; (3) it can be applied impartially to all applicants for royalty reduction; and (4) it will generally result in reproducible results when applied by different qualified petroleum geologists.

This definition allows the department to consider all the relevant information with regard to royalty reduction. Commonality of production and transportation facilities and well bores, as well as shared information and economies of scale provided by having multiple stacked reservoirs under a single lease are important factors in the development of an oil field. Not only do multiple stacked reservoirs have lower development costs, but their development also entails lower risk wells. For example, wells can be plugged back and produced from the shallower horizon if the deeper horizon is not produced due to faulting, lack of sufficient net pay, well bore damage, depletion or other factors. The department's definition of "field" is similar to that used by AOGCC in that it considers multiple vertically separated pools or reservoirs underlying the same lease or leases a single "field."

Utilizing a definition that encompasses all reservoirs or pools within the Milne Point Unit also helps minimize the incentive for the operator and lessees to manipulate production and/or costs from individual reservoirs within the Unit for the purposes of affecting royalty reduction applications.

Note that the department's definition does not prohibit the commissioner from granting selective relief to individual pools or reservoirs, or even individual leases. In this case, the ability to do so is clearly stated by the Milne Point Unit Agreement and not prohibited by statute.

IV. Definition of Reasonable Rate of Return

Similarly, regardless of whether one is guided by State law or the Milne Point Unit Agreement, the applicant and the department disagree on what constitutes "a reasonable rate of return" for the purpose of evaluating a royalty reduction request. Without providing objective standards, both AS 38.05.180(j) and the Milne Point Unit Agreement leave it up to the commissioner to define a reasonable rate of return for royalty reduction purposes. Against this backdrop, the department has an obligation to adopt a standard that is objective and which may be applied consistently without regard to the vagaries of the financial planning standards of individual companies . Furthermore, the standard should provide a positive real rate of return (more than inflation), yet not allow for excessive profit at the expense of the state's royalty share.

Oxy has argued in its August 27, 1990 supplemental brief and in testimony at the public hearing, that, at a minimum, a reasonable rate of return, for royalty reduction, should be defined as the cost of capital to the company plus a marginal profit. There are obvious problems with this standard. First of all, such a standard would vary widely from company to company. Based upon information available to the department, Oxy had a cost of capital at a nominal rate of 9.26%. The eight major North Slope producers' cost of capital ranged from a low of 9.26% (Oxy) to a high of 12.75% (Conoco). Additionally, financial data of this sort are generally not directly available to the public, rates are difficult to monitor over time, and many projects are internally financed by the companies.

Thus, defining a reasonable rate of return standard as the individual firm's cost of capital is not acceptable since it treats every firm differently and as such a rate is difficult if not impossible to verify. Such a standard would provide a different level of relief based upon the company, regardless of the field. To protect the state's interest, royalty relief should be based on the economics of the field and not on a company's real or perceived internal financial characteristics. Further, the standard should be impartially applicable to all lessees. A reasonable rate of return that is

independent of the particular company financing involved should be adopted to avoid possible manipulation of in-house economics simply for royalty reduction purposes.

In its August 27, 1990 supplemental brief, Oxy, like Conoco, cites a number of public utilities law cases in support of its proposed definition of rate of return. These cases are intended to demonstrate examples where the most strict standard for a reasonable rate of return is the cost of capital. However, for royalty reduction purposes, these are invalid analogs. A public utility is granted a rather generous (but capped) rate of return since it is regulated and at the same time must compete with unregulated firms in the capital market. Also, a public utility does not have an opportunity to make large profits in other settings, as does a large, privately owned integrated oil company such as Oxy. Neither Oxy's prices nor its costs are regulated by a public agency; therefore, Oxy has no regulated limits on its potential profitability.

It is the potential for large profits that allows Oxy, or any other oil and gas lessee for that matter, to take the risks inherent in wildcat exploration and oil field development. This provides a freedom of operation not granted to a public utility. It is therefore only proper that a more conservative standard for rate of return be applied to Oxy, and other lessees, in determining whether, and to what extent, a reduction in the state's royalty share of production is appropriate. When all the arguments are stripped away, the stated purposes of the royalty reduction statutes are to prolong the economic life of the field and protect the public interest, not to guarantee the state's lessees a minimum rate of return on every field which they choose to develop.

Standards other than those suggested by Oxy are available to define a reasonable rate of return. For example, the economic yardstick used by the United States Geologic Survey and the U.S. Department of Energy in recent studies has been an after-tax rate of return of 8%. Referring to the development of North Slope reserves in *Economics and the National Oil and Gas Assessment, The Case of Onshore Northern Alaska* (In press Attanasi, Bird, and Mast) the authors state "Fields were considered

commercially developable if a discounted cash flow analysis showed that an after-tax return of 8 percent could be achieved. At the time of the assessment, the 8 percent hurdle rate was being used by the U.S. Department of Energy's Energy Information Administration in the national energy base case forecasts (Jon Rasmussen, Energy Information Administration, oral communication)."

Another potential yardstick for defining a reasonable rate of return is the standard used by the State of Alaska Department of Revenue (DOR) in determining reasonable shipping rates for North Slope crude for the purpose of calculating severance tax obligations. Shippers are allowed the Gross National Product deflator (GNPd) plus two percentage points return to capital as allowable expenses (profits). For the 1980-1989 period, the GNPd fell short of the 90 day Treasury bill rate by 4.4 percentage points. Otherwise stated, DOR has allowed, as a reasonable rate of return, a rate which is, on average, 2.4 percentage points less than the 90 day Treasury bill rate.

The standard which I recommend the department choose to define a "reasonable rate of return" for the purposes of this application is the rate of return for a 90 day Treasury Bill. For the period of 1980-1989 the real rate of return for the 90 day bill was approximately six percent. This standard compares favorably with other potential standards examined by the department.

V. Discretionary Nature of Royalty Reduction

A well established rule of interpretation specifies that "may" refers to discretionary action, while "shall" dictates mandatory action. Similarly, "may not" constitutes a mandatory prohibition.

AS 38.05.180(p) states the commissioner "may ... change ... royalty requirements ...." Paragraph 18(h)(8) of the Milne Point Unit Agreement provides that the State "may reduce Lessee's obligation to pay royalty ...." Thus, both AS 38.05.180(p) and paragraph 18(h)(8) of the Milne Point Unit Agreement permit royalty reductions, but they do not mandate royalty reductions, except where a denial of a royalty reduction would be arbitrary or unreasonable.

AS 38.05.180(j), both before and after amendment by HB 128, mandates promulgation of regulations governing applications for royalty reduction: "the commissioner **shall** adopt regulations ...." However, the regulations are "to **allow** reduction of royalty ...." The word "allow," like "may," is permissive, not mandatory. AS 38.05.180(j), both before and after amendment by HB 128, then uses mandatory language to specify one instance in which royalty reduction is **not** allowed: "The commissioner **may not** grant a reduction of royalty" unless the applicant has made a clear showing that its revenue from the field is insufficient to produce a reasonable rate of return on its total investment in the field. In short, while AS 38.05.180(j) contains some compulsory directives, it also permits denial of an application where not unreasonable or arbitrary to do so.

VI. Evaluation of Application Under AS 38.05.180(p)

AS 38.05.180(p) states:

> To conserve the natural resources of all or a part of an oil or gas pool, field, or like area, the lessees and their representatives may unite with each other, or jointly or separately with others, in collectively adopting or operating under a cooperative or a unit plan of development or operation of the pool, field or like area, or a part of it, when determined and certified by the commissioner to be necessary or advisable in the public interest. **The commissioner may,** with the consent of the holders of leases involved, establish, **change,** or revoke drilling, producing, and **royalty requirements of the leases** and adopt regulations with reference to the leases, with like consent on the part of the lessees, in connection with the institution and operation of a cooperative or unit plan **as the commissioner determines necessary or proper to secure the proper protection of the public interest.**

(Emphasis added).

Oxy's application, as initially submitted, represented that the Milne Point Unit Kuparuk Formation had an expected field life of twenty-five years, three years of which have now elapsed. Oxy's application states that if the State reduced its royalty to 5%, the Kuparuk formation would produce 1.8 million barrels more

than it would otherwise produce in the three years following the first twenty-five years of production. Given a working interest of 10.477%, Oxy's gross share of this additional production equals approximately 194,000 barrels.

In evaluating Oxy's application, the department must determine whether the public interest would best be served by the State's receipt of a 20% royalty over a remaining field life of twenty-two years, or by the State's receipt of a 5% royalty over a remaining field life of twenty-five years and the production of an additional 194,000 barrels of oil twenty-two to twenty-five years from now. This determination cannot be made without reference to the wellhead value of Milne Point oil.

It is impossible to accurately calculate the wellhead value of production occurring over the next twenty-two to twenty-five years. The impossibility of the task is exemplified by the wide range of values for oil produced from the Kuparuk Formation in the Milne Point Unit in 1990 alone, when the reported wellhead value over doubled between June and September. However, the department is able to model the effects in a gross sense by selecting a low estimated average value and a high estimated average value, then calculating the costs and benefits of granting the requested royalty reduction should values approaching either of these extremes prove accurate.

In this analysis, the department selected a low average Milne Point wellhead value of $12 per barrel and a high average Milne Point wellhead value of $22. These wellhead values were chosen to represent possible average wellhead values for the entire life of the field. These wellhead values roughly correspond with United States West Coast average prices of $20 and $30 per barrel, respectively.

Assuming first that the average wellhead value for oil produced from the Kuparuk Formation is $12 per barrel and the State's royalty is reduced from 20% to 5%, the State will lose approximately $10,000,000 in royalties on oil produced during the next twenty-two years, and gain approximately $116,000 in royalties on oil produced twenty-two to twenty-five years from now. Total direct benefit from Oxy's additional production under a reduced royalty rate is estimated to be 194,000 barrels of oil valued at $2,328,000.

Assuming that the average wellhead value is $22 per barrel and the State's royalty is reduced from 20% to 5%, the State will lose approximately $17,000,000 in royalties on oil produced during the next twenty-two years, and gain approximately $213,000 in royalties on oil produced twenty-two to twenty-five years from now. The incremental volume of oil that would be produced due to a royalty reduction in this case would be valued at approximately $4,268,000.

Under both scenarios the cost of the royalty reduction to the State is roughly four times the combined value of the direct benefits to the state and public. These analyses were conducted in constant 1989 dollars. Obviously, had they been done in present value terms, the disparity between costs and benefits would have been even greater.

But there are other benefits which may be obtained by reducing the royalty rate to 5%. By letters dated May 16 and October 9, 1990, the field operator, Conoco, committed to expand its 3-D seismic program, and, dependent on the outcome of the seismic program, possibly drill two additional wells to evaluate three regions of the Kuparuk Formation within the Milne Point Field. These wells would be targeted to delineate the resource potential of several small fault blocks and/or the down-dip limit of the field. Conoco first termed the magnitude of reserve additions attributable to these operations as "totally speculative." Subsequently, Conoco provided reserve estimates for one of the three regions and risk factors for all three regions. Based on the relatively low reserve estimate, coupled with the risk factor, the conditional nature of the commitment to drill, and ownership interests of other parties in the reserves, the department concludes that the potential incremental benefits of royalty reduction are insufficient to tip the scales in favor of granting the reduction requested.

If future seismic acquisition and interpretation supports Conoco's current geologic mapping, and the State reduces its royalty to five percent, Conoco will drill two additional production wells which, based on Conoco's expectations, could produce approximately an additional 3 million barrels of oil. Assuming all this additional production underlines leases in which Oxy has a working interest, its share of this additional production would be 314,310 barrels of oil. The state's royalty share of this production at the five percent royalty would be 15,715 barrels. Other benefits from this additional drilling would include the

short term employment of a rig crew and support personnel (approximately two weeks to drill and complete each well). Unequivocally, the value of speculative additional production that may be derived from this additional drilling is inadequate to offset the forgone royalty.

Based on the extraordinary value of lost royalties, the modest benefit of a potential 194,000 barrel increase in production, and the highly speculative, conditional, and relatively minor benefits of Conoco's and Oxy's commitment to additional exploration and development activities, it is extremely difficult to make a finding that granting the royalty reduction which Oxy requests is either necessary or proper to secure the proper protection of the public interest.

VII. Evaluation of Application Under AS 38.05.180(j), Prior to Amendment By HB 128 in 1990

AS 38.05.180(j), as it existed at the time the Milne Point Unit Agreement was executed and at the time Oxy's application was submitted, stated:

> **AS 38.05.180(j) "To prolong the economic life of an oil and gas field, the commissioner shall adopt regulations for all bidding methods to allow reduction of royalty on leases within the field to compensate for increasing costs in the later stages of production decline. The commissioner may not grant a reduction of royalty until two years' initial production from the field has occurred and each lessee requesting the reduction has made a clear showing that the revenue from all hydrocarbons produced from the field is insufficient to produce a reasonable rate of return with respect to that lessee's total investment in the field."**

(Emphasis added).

As with AS 38.05.180(p), relief under AS 38.05.180(j) is discretionary. However, the department should not exercise its discretion in favor of royalty reduction unless the reduction is in the public interest. For the reasons discussed in Part VI, above, granting the royalty reduction as requested by Oxy is not in the public interest.

To qualify for relief under AS 38.05.180(j), an applicant must establish that the relief requested: (1) follows two years initial production from the field; (2) will prolong the economic life of the field; (3) will compensate for increasing costs in the later stages of production decline; **and** (4) is necessary to produce a reasonable rate of return on the applicant's total investment in the field.

Oxy submitted its application for royalty reduction immediately following two years of cumulative production from the Kuparuk Formation of the Milne Point field; therefore, the requirement of two years initial production from the field has been met. However, Oxy has not established that the requested royalty reduction will significantly prolong the economic life of the field. While the field life **might** be extended by three years, more than twenty years in the future, the number of years added or not added is not relevant--the number of additional barrels recovered is the primary factor to consider. Oxy's unconditional commitment to increased production is limited to 194,000 barrels. This volume represents only a tiny portion of the estimated production for the Kuparuk Formation, and an even lesser percentage of estimated production for the Milne Point field. Given the cost to the State of the royalty reduction requested, the amount of potential new production 20+ years hence is almost inconsequential in both absolute and relative terms.

Having failed the second part of a four part test for royalty reduction under AS 38.05.180(j), it is unnecessary to examine elements three and four. However, brief mention of the two remaining elements is appropriate. AS 38.05.180(j) restricts royalty reduction to instances in which it will compensate for increasing costs in the later stages of production decline. First, the department has received no information that would indicate the Milne Point field is in the later stages of production decline. To the contrary, Conoco, the field operator, has announced plans to develop the Schrader Bluff Formation within the Milne Point field with the ultimate goal of at least doubling overall production from the field. Oxy has the option to participate in this field development project. Second, the department interprets this requirement as limiting the amount of relief which may be granted to that amount necessary to offset the increase in costs. It is impossible to ascertain whether royalty relief granted after three years of production in a field with an estimated field life of twenty-five to twenty-eight years would compensate for, and be commensurate with, increasing costs in the

later stages of production decline. Given the volatility of future oil prices and the remoteness of late-stage costs, the department should not conclude that this standard would be met by granting the requested royalty reduction at this time.

Finally, AS 38.05.180(j) requires the applicant to make a clear showing that the revenue generated by the field is insufficient to produce a reasonable rate of return on the total investment in the field. A clear showing requires evidence which is precise, explicit, and which directly establishes the point. It is very difficult, if not impossible, to provide such evidence here, since the Milne Point field is in the very early stages of production. Use of estimated value, production, and cost data for the remaining twenty-two to twenty-five year life of the field adds a high level of uncertainty to determining the long-term validity of any purported "need" for Oxy's royalty reduction. Particularly disturbing is the unreliability inherent in estimating the value of oil to be produced over the next twenty-two to twenty-five years. As mentioned earlier, this unreliability is dramatically underscored by the over doubling of reported wellhead values from the Milne Point Unit between June and September 1990.

Estimating revenue from future production is further complicated by a lack of knowledge regarding the potential volume and value of future production from other pools in the Milne Point field, such as the Schrader Bluff Formation, as well as by price and technology sensitive enhanced oil recovery techniques which may significantly increase total production from all reservoirs or pools within the Milne Point field.

On the other hand, since much of the major field facility development has already occurred, the cost estimates for the remaining field life are easier to approximate. According to the data submitted by Conoco on June 13, 1990, about 87% of the capital investment in field facilities has been completed, leaving only relatively minor capital investment expenses to be estimated. This, however, does not include the costs associated with Schrader Bluff development and production.

In short, the department may reasonably conclude it impossible to make a clear showing that the revenue generated by the Milne Point field over its entire life will be insufficient to produce a reasonable rate of return on the total investment

in the field when but a small fraction of the minimum estimated field life has transpired.

In conclusion, Oxy's application should not be granted as requested under AS 38.05.180(j) (as it existed before it was amended by HB 128). Oxy has not established that reducing the royalty rate on the Kuparuk Formation from 20% to 5% would significantly prolong the life of the Milne Point field. A minimal extension of the field at a very high cost to the State is not in the public interest. Furthermore, the uncertainties inherent in estimating revenue and costs for the next twenty-two to twenty-five years allow the commissioner to conclude that Oxy cannot adequately show either the magnitude of increasing costs in the later stages of production decline or total field life rate of return.

VIII. Evaluation of Application Under AS 38.05.180(j), As Amended By HB 128 in 1990

AS 38.05.180(j) was amended by HB 128, effective September 12, 1990. It now reads:

> **To prolong the economic life of an oil and gas field or to reestablish commercial production of shut-in oil or gas that would not otherwise be economically feasible,** the commissioner shall adopt regulations to allow reduction of royalty on leases. The commissioner may not grant a reduction of royalty unless the lessee requesting the reduction makes a clear showing that the revenue from the lessee's share of all hydrocarbons produced from the field is and is likely to continue to be insufficient to produce a reasonable rate of return with respect to the lessee's total investment in the field. The commissioner may condition a royalty reduction granted under this subsection in any way to protect the state's interest, including restoration of the state's royalty share in the event of an increase in the price of oil or gas. Before approving a royalty reduction, the commissioner shall make a written finding that **the state has obtained the maximum possible economic return that is compatible with allowing a reasonable rate of economic return for the lessee,** and send copies of the finding to all members of the legislature.

(Emphasis added).

As with AS 38.05.180(p), and AS 38.05.180(j) prior to its amendment by HB 128, relief under the amended standard is discretionary. The department, however, should not exercise its discretion in favor of royalty reduction unless the reduction is demonstrated to be in the public interest. For the reasons discussed in Part VI, above, granting royalty reduction as requested by Oxy, is not in the public interest.

Under AS 38.05.180(j) as amended by HB 128, royalty relief cannot be granted unless it will either prolong the economic life of an oil and gas field or reestablish commercial production of shut-in oil or gas that would not otherwise be economically feasible. The royalty reduction requested by Oxy will not substantially prolong the economic life of the Kuparuk Formation or Milne Point field for the reasons discussed in Part VII, above. Nor is the Kuparuk Formation shut-in, as it was previously. Therefore, Oxy's application fails these alternative requirements of AS 38.05.180(j), as amended by HB 128.

As 38.05.180(j), as amended, also retains the requirement of a clear showing that revenue from the field is insufficient to produce a reasonable rate of return on total field investment. The department's analysis of this requirement is the same under both the former AS 38.05.180(j) and its current amended version. (See Part VII, above).

The 1990 amendment to AS 38.05.180(j) specifies that an application for royalty reduction cannot be approved unless the commissioner makes a written finding that the State has obtained the maximum possible economic return that is compatible with allowing a reasonable rate of economic return for the applicant. Due to volatile oil prices, risks inherent in oil and gas production, and uncertain future costs, the department cannot find that the State will obtain its maximum possible economic return without providing for the recapture of foregone royalties in the event a lessee ultimately achieves more than a predetermined reasonable rate of return. However, in this instance the department need not craft a limited or conditional royalty relief, since the royalty relief requested is inappropriate for other reasons, as discussed above.

IX. Milne Point Unit Agreement, Paragraph 18(h)(8)

Oxy argues in its August 27, 1990 supplemental brief that paragraph 18(h)(8) of the Milne Point Unit Agreement governs its application for royalty reduction; and that AS 38.05.180 (p) and (j) apply only to the extent that they are not inconsistent with the unit agreement. Paragraph 18(h)(8) states:

> Reduction of Royalty. After two years' initial production from the field in which the leased area is located has occurred, the State may reduce Lessee's obligations to pay royalty on all of the leased area or on any tract or portion thereof segregated for royalty purposes upon (1) request by Lessee and (2) a clear showing by Lessee that the revenue from all oil, gas and associated substances produced from the field is insufficient to produce a reasonable rate of return with respect to Lessee's total investment in the field.

Oxy's argument that paragraph 18(h)(8) prevails where inconsistent with AS 38.05.180(p) or (j) appears to be based on an incomplete reading of paragraph 1 of the Unit Agreement, which states:

> The Alaska Land Act ... and all valid and pertinent oil and gas statutes and regulations including the oil and gas operating statutes and regulations in effect as of the effective date hereof or hereafter issued thereunder governing drilling and producing operations, **not inconsistent with the terms hereof or the laws of the State of Alaska** are hereby accepted and made a part of this agreement.

(Emphasis added). Oxy chooses to ignore that all statutes not inconsistent with the laws of the State of Alaska are incorporated by reference in the Unit Agreement. Since the statutes are the laws of the State of Alaska, they cannot be inconsistent with the laws of the State of Alaska (except to the extent that one or more statutes are contrary to the United States or Alaska constitutions). Therefore, AS 38.05180(j) and (p) are incorporated by reference in the Unit Agreement, and are thus every bit as much a part of the Unit Agreement as is paragraph 18(h)(8).

In any case, a state agency is without authority to enter into an agreement in conflict with applicable statutes. Thus, even without an explicit incorporation of

Alaska's statutes by reference in Paragraph 1 of the Milne Point Unit Agreement, the statutes control when in conflict with the Unit Agreement.

X. Summary

In this instance, I have recommended that the requested royalty reduction should be denied under AS 38.05.180(p), (j), and (j), as amended by H.B. 128 since the department concludes that Oxy has failed to demonstrate:

(1) that granting the requested royalty relief will be in the public interest;
(2) that reducing the royalty from 20% to 5% will significantly prolong the economic life of the field; and
(3) a clear showing that its revenue from oil, gas, and associated substances produced from the field is insufficient to produce a reasonable rate of return with respect to Oxy's total investment in the field.

The statutes and regulations do not discuss the quantity or quality of data needed to demonstrate a clear showing (though, obviously, "clear showing" is a high standard) that Oxy's revenue from the field is insufficient to produce a reasonable rate of return with respect to its total investment in the field. Similarly, the statutes and regulations do not list precisely the quantity or quality of data needed to demonstrate that the economic life of the field will be significantly prolonged by a royalty reduction. These determinations must be made by the commissioner based on the discretionary power granted by the statutes, department regulations, and the Milne Point Unit Agreement. However, it becomes apparent that, especially in the case of a field such as Milne Point, with only a few years of production history, determining the long term profitability of the field with any certainty is virtually impossible, especially when the lessees

continue to produce oil and develop new reserves under the existing 20% royalty rate.

Even though it is recommended that Oxy's application for a royalty reduction to 5% be denied, the division felt obligated to carefully analyze the data submitted to determine if an alternative approach for royalty reduction could be developed which would meet the statutory requirements. Among the possibilities examined were a sliding scale royalty based on wellhead value, short term relief, relief down to a floor of 12.5%, and combinations of these three methodologies. These limited and/or conditional alternatives to a complete denial were determined to be unacceptable since in all cases examined, even ignoring Oxy's failure to make a clear showing, the estimated benefit to the state and public was substantially less than the estimated revenue lost by the state in forgone royalty. Therefore, even a limited or conditional royalty does not appear to be in the public interest at this time.

ENCLOSURE 5

Mark Myers

IN THE SUPERIOR COURT FOR THE STATE OF ALASKA

FIRST JUDICIAL DISTRICT AT JUNEAU

CONOCO, INC., a Delaware Corporation, and OXY USA, INC.,

Plaintiffs,

vs.

STATE OF ALASKA, DEPARTMENT OF NATURAL RESOURCES,

Defendant.

No. 1JU-91-796 CI

ORDER

On August 28, 1991, oral argument was held on the state's motion to dismiss. After hearing the arguments, the court granted the state's motion but delayed a final ruling pending review of the proprietary/governmental distinction argued by Conoco. The court has reviewed this issue and holds that although some jurisdictions would apply this distinction, the direction of the Supreme Court to date appears to require dismissal of this action.

In University of Alaska v National Aircraft Leasing, Ltd., 536 P.2d 121, 128 (Alaska 1975), the Alaska Supreme Court noted that it had previously abandoned the proprietary/governmental distinction with respect to municipal tort liability analysis in City of Fairbanks v Schaible, 375 P.2d 201, 208 (Alaska 1962). The Court then extended the Schaible

Alaska Court System

Enclosure 5

ruling to suits involving the state or its agencies in tort liability cases. University of Alaska, 536 P.2d at 128. The Court noted that other jurisdictions still acknowledged the proprietary/governmental distinction, but refused to follow those jurisdictions. Id.

More recently, the Court refused to apply the distinction to a dispute involving real property. Mount v Curran, 657 P.2d 392, 395 (Alaska 1982). The Court recognized that other jurisdictions allow land to be adversely possessed against municipalities if the municipal land is not being held for public purposes. Id. The Court pointed out that this exception to the general rule prohibiting adverse possession against the government is a reflection of the proprietary/governmental distinction. Id. Again, as in the previous cases, the Alaska Supreme Court refused to follow the jurisdictions recognizing the distinction.

In a 1986 case, the Supreme Court made reference to the distinction in the context of a local hire issue. Robinson v Francis, 713 P.2d 259, 264 (Alaska 1986). The Court discussed the distinction and its impact on the analysis employed under the privileges and immunities clause, but did not hold that Alaska had or would adopt the use of the distinctions in this or other areas of legal analysis. Id.

Conoco has called the court's attention to several out-

of-state cases that specifically apply the distinction in situations similar to the situation occurring here. Again, however, the Alaska Supreme Court has recognized that other jurisdictions have relied on the distinction in various situations. Nonetheless, in two situations, tort liability and municipal real estate problems, the Court held that the distinction would not be applied. This court believes that the Alaska Supreme Court will not follow the out-of-state precedent in this instance.

Furthermore, in at least two of the cases relied on by Conoco, distinct statutory differences exist.

In, General Land Office of State of Texas v Rutherford Oil Corporation, 802 S.W.2d 65, 69 (Texas App. 1990), the Texas court held that the GLO only had the statutory authority to audit the books, but it did not have the authority to require payment of the royalties. Likewise, in Anson Company v Commissioner of the Land Office of the State of Oklahoma, Order 74766 Oklahoma Supreme Court (March 26, 1988), that court held that the oil and gas lease did not give the commissioners adjudicative authority over the rights of the parties. Here, paragraph 18(h)(8) and A.S. 38.05.180(j) and (p) give the Department of Natural Resources Commissioner the authority to determine royalty reduction.

Conoco also questioned why the state was able to seek

original jurisdiction in the Amerada Hess litigation (now called the North Slope Royalty Litigation) and yet in this case, the same option is being denied. In Amerada Hess, the parties contractually agreed to litigation if they could not resolve the issues themselves. See, ANR Royalty Litigation, 1JU-77-847 CI, Plaintiff's Complaint for Declaratory Judgment, Para. 3I. Here, Conoco contracted to have the determination of royalty reduction decided by DNR.

Finally, Conoco argues that there was an inadequate administrative process provided in this matter. However, even if this is true, Conoco has a remedy through the appellate process. The matter may be remanded back to the administrative agency for appropriate proceedings.

For the above reasons, the state's Motion to Dismiss is granted.

DATED at Sitka, Alaska, this 10th day of September, 1991.

Larry C. Cleveland
Superior Court Judge

ENCLOSURE 6

Jim K BTOC Kgmt

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Department of Law

JUN 09 1993

Office of the Attorney General
Anchorage Branch
Anchorage, Alaska

THE SUPREME COURT OF THE STATE OF ALASKA

CONOCO, INC., a Delaware corporation, and OXY USA, INC., a Delaware corporation, Appellants, v. STATE OF ALASKA, DEPARTMENT OF NATURAL RESOURCES, Appellee.	Supreme Court File No. S-4803 Superior Court File No. 1JU-91-796 Civil Corona Mesa Pt Royalty Reduction file MEMORANDUM OPINION AND JUDGMENT* [No. 0668 - June 9, 1993]

Appeal from the Superior Court of the State of Alaska, First Judicial District, Juneau, Larry C. Zervos, Judge.

Appearances: Jeffrey W. Bush and Jonathan K. Tillinghast, Birch, Horton, Bittner & Cherot, Juneau, for Appellants. [redacted] Assistant Attorney General, Anchorage, and Charles E. Cole, Attorney General, Juneau, for Appellee.

Before: Moore, Chief Justice, Rabinowitz, Burke, Matthews, and Compton, Justices.

I. INTRODUCTION

This case arises from a dispute between the Department of Natural Resources (DNR) and two oil companies--Conoco, Inc. (Conoco) and OXY USA, Inc. (OXY)--over the interpretation of a royalty reduction clause in an oil and gas lease unit agreement. After DNR denied them a royalty reduction, Conoco and OXY filed two suits: an administrative appeal challenging DNR's decision, and an original action raising several claims in contract. On the state's motion, the superior court dismissed the original action, concluding that Conoco and OXY must pursue all their claims in the

* Entered pursuant to Alaska Appellate Rule 214.

administrative appeal. The court also awarded attorney's fees to the state. We affirm.

II. FACTS AND PROCEEDINGS

This case involves four oil and gas leases on the North Slope. The predecessor in interest to Conoco and OXY obtained these leases in 1969, and paid a 12.5 percent royalty to the state. In 1979, Conoco and OXY's predecessor in interest proposed to consolidate the leases, which were about to expire, and form a unit agreement. DNR, however, refused to approve the unit agreement without an increase in the royalty rate to 20 percent. The parties agreed to the rate increase. A provision of the unit agreement permits the state to grant a royalty reduction if production from the oil field is low. The state and the two companies dispute whether this clause requires DNR to grant Conoco and OXY a royalty reduction.

In 1990, Conoco and OXY applied for a reduction in the royalty rate to five percent. The process by which DNR reviewed the application involved public but nonadversarial hearings, which were not adjudicatory in nature. Conoco and OXY allege numerous flaws in the review process, including the absence of any adjudicatory hearing, the lack of an opportunity to cross-examine DNR staff, and the existence of ex parte communications between DNR staff and the officer presiding over the hearings. The hearing officer recommended that the Commissioner of Natural Resources deny

the applications for royalty reduction. The Commissioner substantially adopted this recommendation, and denied the applications.

In response, Conoco and OXY filed two actions in the lower courts. One was an administrative appeal to the Superior Court, brought under Part Six of the Appellate Rules,[1] and challenging the Commissioner's decision. Conoco, Inc. v. State, Dep't of Natural Resources, No. 1JU-91-797, 798 CI (Consolidated) (Alaska Super., Mar. 17, 1992). The other was an original, independent action before the superior court, raising claims in contract, and demanding a jury trial. The companies sought judgment in their favor for, among other things, specific performance, a reduction in the royalty rate, reformation of the unit agreement, and damages.

In the original action, the state brought a motion to dismiss under Alaska Civil Rule 12(b)(1) for lack of subject matter jurisdiction.[2] Judge Larry Zervos granted the state's motion and

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1 Where the law allows for appeals of an administrative agency's actions, the superior court exercises jurisdiction over such appeals. AS 22.10.020(d). Part Six of the Appellate Rules (Rules 601-612) governs administrative appeals to the superior court. Alaska R. App. P. 601(a).

2 Civil Rule 12(b) states in part:

> Every defense, in law or fact, to a claim for relief in any pleading . . . shall be asserted in the responsive pleading thereto if one is required, except that the following defenses may at the option of the pleader be made by motion: (1) lack of jurisdiction over the subject matter . . . .

dismissed Conoco's and OXY's contract claims, holding that the companies must raise them in the administrative appeal. Judge Zervos subsequently awarded attorney's fees to the state. Conoco and OXY appeal Judge Zervos's decision.[3]

III. DISCUSSION

No matter how it is denominated, a claim is functionally an administrative appeal, and a party must raise it as such, if it requires the court to determine the propriety of an agency determination. E.g., Fairbanks N. Star Borough v. State, 826 P.2d 760, 762 (Alaska 1992); see also Fedpac Int'l, Inc. v. State, Dep't of Revenue, 646 P.2d 240, 241 (Alaska 1982); Alaska R. App. P. 602. If a plaintiff tries to style a suit as an independent action by raising issues different from those that the agency considered, but the relief sought is basically identical to that sought from the agency, then the suit must be dismissed. Fairbanks N. Star Borough, 826 P.2d at 763; Fedpac Int'l, Inc., 646 P.2d at 240-41.

Even when a dispute involves contractual issues, plaintiffs must nonetheless pursue their claims by an administrative appeal, rather than an original action. See, e.g., Fairbanks N. Star Borough, 826 P.2d at 761, 764-65 (questions of rescission and mutual mistake regarding easement agreement);

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3 Conoco and OXY also discuss the outcome of the administrative appeal before Judge Weeks. Because this appeal challenges Judge Zervos's action, we will not discuss the propriety of Judge Weeks's decision. If Conoco and OXY disagree with Judge Weeks's decision, they may appeal it separately.

Diedrich v. City of Ketchikan, 805 P.2d 362, 365-66 (Alaska 1991) (alleged breach of an employment contract); State v. Lundgren Pac. Constr. Co., 603 P.2d 889, 890, 892-93 (Alaska 1979) (dispute over contract to build ferry terminals). To do otherwise would let almost any litigant avoid the administrative appeal rules, just by alleging contract or other common law claims in his or her complaint. See Fedpac Int'l, Inc., 646 P.2d at 242.

Conoco and OXY's contract claims do not entitle the two companies to an original, independent action. The companies argue that their claims are not in fact related to DNR's decision, because they seek a reformation of the unit agreement to delete the 1979 royalty increase altogether, not simply a reversal of DNR's decision. The claim for reformation, the companies argue, could have been brought at any time, and is raised along with the appeal only because until now they were not aware of how DNR would read the disputed provisions. Nevertheless, the objective of Conoco and OXY clearly is to escape the unit agreement's current royalty rates, through either a reversal of DNR's decision or a reformation of the agreement to eliminate the increase in rates from the start. Therefore, no matter how they characterize their claims, Conoco and OXY in effect have challenged DNR's denial of a rate reduction, and must pursue their remedies through an administrative appeal.[4]

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4 Conoco and OXY also argue that under this court's holding in Owsichek v. State, Guide Licensing & Control Bd., 627 P.2d 616 (Alaska 1981), they are entitled to file an original action because their suit includes claims for declaratory judgment. If a request (continued...)

Conoco and OXY argue that because DNR's leasing arrangements put the agency in the position of a private market participant, the companies may sue the agency in an original action, just as they could with any other private party. However, we have not recognized a distinction between an agency's proprietary and governmental activities. E.g., Mount v. Curran, 657 P.2d 392, 395 (Alaska 1982) (disallowing adverse possession of public property, even if state acquired property for nonpublic purpose); University of Alaska v. National Aircraft Leasing, Ltd., 536 P.2d 121, 128-29 (Alaska 1975) (refusing to apply distinction to university activities). In particular, we have rejected the argument that DNR's involvement in oil and gas leasing was a proprietary function. State, Dep't of Natural Resources v. Arctic Slope Regional Corp., 834 P.2d 134, 143 (Alaska 1991) ("We find the line the companies draw between 'regulatory' and 'proprietary' functions more clear in theory than in practice."). Holding that the mandatory disclosure to DNR of data on exploratory wells is not a taking of property, we found that DNR's activities promoted the general welfare of the citizenry and were thus a valid exercise of

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4 (...continued)
for a declaratory judgment requires review of only a statute or a regulation, and not an agency decision, then the provisions for administrative appeals do not apply, and a plaintiff may pursue an original action. Owsichek, 627 P.2d at 619 (interpreting predecessor to Appellate Rule 602). Here, the companies' declaratory judgment claims ask the court to interpret the provisions of the unit agreement, not a statute or regulation. Therefore, Conoco and OXY seek a direct review of DNR's decision, and Owsichek's rule on declaratory judgments is inapplicable.

the police power.[5] See id. at 143-44, 145.

Assuming that Conoco and OXY's complaints about DNR's review process are valid,[6] they nonetheless do not require an original action. If the court on appeal finds that agency procedures did not conform with due process requirements, then the remedy is not an original action, but rather a trial de novo on appeal. Lundgren Pac. Constr. Co., 603 P.2d at 896. If agency procedures themselves are proper, but they were not followed in a particular case, then the remedy is a remand to the agency. Id. If less formal agency hearing procedures lead to defects in the record, such flaws may be corrected in the administrative appeal. Fedpac Int'l, Inc., 646 P.2d at 243. Thus the proper vehicle for challenging DNR's review process remains an administrative appeal. We need not examine the process to conclude that an original action would be inappropriate.

Because an administrative appeal is the proper vehicle for the claims of Conoco and OXY, the parties have no right to a jury trial. In civil cases, the right to a jury trial "is preserved to the same extent as it existed at common law." Alaska

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5 To reach our conclusion, we looked to the legislative intent behind Alaska's statutes on oil and gas leases. See AS 38.05.180(a), quoted in part in Arctic Slope Regional Corp., 834 P.2d at 143.

6 In reviewing a motion to dismiss under Civil Rule 12(b), a court must presume all the factual allegations in the complaint to be true, and must view the evidence in the light most favorable to the nonmoving party. Kollodge v. State, 757 P.2d 1024, 1026 (Alaska 1988).

Const. art. I, § 16. On the other hand, in cases where questions of fact arise under statutory actions rather than common law, a court may decide such issues without a jury. Diedrich v. City of Ketchikan, 805 P.2d 362, 366-67 (Alaska 1991) (deeming an administrative appeal the proper vehicle for employee's wrongful discharge suit); see also Benson v. City of Nenana, 725 P.2d 490, 491 (Alaska 1986) (in case under Workers' Compensation Act, allowing bench trial without jury where exclusive remedy defense raised). DNR has the power to administer oil and gas leases and determine royalty reductions in the interest of the general welfare. See AS 38.05.180(a), (f), (j). The legislature also provided for administrative appeals of agency determinations. AS 22.10.020(d); see Alaska R. App. P. 601-612. Therefore, no jury trial is required, because no action at common law exists here.[7]

Additionally, Conoco and OXY contend that Judge Zervos should not have awarded attorney's fees under Alaska Civil Rule 82, because this case had no prevailing party. We will overturn the trial court's determination of a prevailing party only for an abuse of discretion. Howard S. Lease Constr. Co. v. Holly, 725

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7 Conoco and OXY extensively analyze the jurisprudence of the U.S. Supreme Court, arguing that this body of law supports their arguments for a jury trial. However, the Seventh Amendment of the U.S. Constitution does not apply to state court proceedings. E.g., Minneapolis & St. Louis R.R. v. Bombolis, 241 U.S. 211, 217 (1916). The U.S. Supreme Court case on which Conoco and OXY rely most heavily finds a right to a civil jury trial when the government acts in a private proprietary capacity. Granfinanciera, S.A. v. Nordberg, 492 U.S. 33, 51-52 (1989). In Alaska, no distinction between proprietary and governmental capacities as yet exists.

P.2d 712, 720 (Alaska 1986). A prevailing party is one who wins on the main issue in dispute, provided that the issue has been joined. Foss Alaska Line, Inc. v. Northland Servs., Inc., 724 P.2d 523, 526 (Alaska 1986).

A dismissal for lack of subject matter jurisdiction is without prejudice, so in a technical sense no issues have been joined and no prevailing party yet exists. On the other hand, we do not approach the definition of a prevailing party in such a rigid fashion. See Miller v. Wilkes, 496 P.2d 176, 178 (Alaska 1972) (upholding award of attorney's fees to defendant, even though plaintiff had voluntarily dismissed case without prejudice under Alaska Civil Rule 41, where issue practically had been joined because defendant filed documents resembling an answer); Hart v. Wolff, 489 P.2d 114, 119 (Alaska 1971) (upholding award of attorney's fees to defendant after dismissing plaintiff's complaint without prejudice for failure to comply with a discovery order). Conoco and OXY's independent action required the state to expend time and money on considerable motion-related paperwork and oral arguments, even if the state simply challenged the trial court's jurisdiction. Therefore, the issues here were joined in a practical sense, and Judge Zervos did not abuse his discretion by awarding the state attorney's fees.

AFFIRMED.

ORDER AWARDING FEES AND COSTS

File No. S-4803

Under Appellate Rules 508(e) and (f)(1), attorney's fees of $1000 are awarded to appellee, and appellee shall serve and file with this court by June 21, 1993 an itemized and verified bill of costs in compliance with Appellate Rule 508(d).

Entered at the direction of on June 9, 1993.

CLERK OF THE SUPREME COURT

Deputy Clerk

ENCLOSURE 7

Conoco - OXY Settlement

SETTLEMENT AGREEMENT AND MUTUAL RELEASE

This SETTLEMENT AGREEMENT and MUTUAL RELEASE (collectively "Agreement") is effective as of December 30, 1993, by and among Conoco, Inc., ("Conoco"), OXY USA Inc. ("OXY"), and the State of Alaska ("State").

RECITALS

This Agreement is made with reference to the following facts:

Royalty Reduction Facts

1. On February 28, 1990 and June 11, 1990, Conoco and OXY, respectively, applied to the State to reduce the royalty rate on certain State leases within the Milne Point Unit ("MPU"). The Commissioner ("Commissioner") of the Department of Natural Resources ("DNR") denied those royalty reduction applications on April 17, 1991.

2. On May 22, 1991, Conoco and OXY appealed the Commissioner's denial of the royalty reduction applications to the superior court in Conoco Inc. v. State of Alaska, 1-JU-797 Civ., and OXY USA Inc. v. State of Alaska, 1-JU-798 Civ. (collectively "Royalty Reduction Administrative Appeal"). Conoco and OXY claim in the Royalty Reduction Administrative Appeal that they are contractually entitled to pay a five percent royalty on all Kuparuk River formation oil production from certain MPU leases. The State claims that Conoco and OXY are contractually required to pay a twenty percent royalty on Kuparuk River formation production from the MPU leases bearing a twenty percent royalty rate and twelve and one-half percent royalty on production from the remaining leases within the MPU, and that Conoco and OXY are not entitled to a royalty reduction either under applicable statutes and regulations, or the MPU Agreement. The Royalty Reduction Administrative Appeal remains pending before the superior court.

3. On May 22, 1991, Conoco and OXY sued the State in Conoco Inc. and OXY USA, Inc. v. State of Alaska, 1-JU-796 Civ. ("the Contract Action"). In the Contract Action, Conoco and OXY claim damages of not less than $16 million for alleged breach of the royalty reduction terms of the MPU

Enclosure 7

Agreement, seek a prospective reduction of royalties, and seek to reform the MPU Agreement to remove the contract provision requiring that they pay a twenty percent royalty, rather than a twelve and one-half percent royalty, on certain leases. The State denies any breach of contract or basis for reformation, and asserts that Conoco and OXY may not pursue their royalty reduction dispute with the State through a common law action independent of the Royalty Reduction Administrative Appeal. The superior court dismissed the Contract Action and awarded attorneys' fees and costs of $2,250 and $1,087.27, respectively, to the State. Conoco and OXY appealed the dismissal to the Alaska Supreme Court in Conoco Inc. and OXY USA Inc. v. State of Alaska, No. S-4083 (the "Supreme Court Appeal"). On June 9, 1993, the supreme court affirmed the superior court's dismissal of the Contract Action in Conoco, Inc. v. State, Op. No. 0668 (Alaska, June 9, 1993), affirmed the superior court's award of fees and costs, and awarded attorney's fees of $1,000 to the State for the appeal.

Discovery Royalty Facts

4. On September 7, 1989, Conoco applied to the State for certification of its Milne Point G-1 well as the first well to discover oil in commercial quantities in the Schrader Bluff formation, and requested an award of a five percent discovery royalty for that well. On January 16, 1992, the Commissioner denied the discovery royalty application.

5. On February 14, 1992, Conoco appealed the Commissioner's denial of the discovery royalty application to the superior court in Conoco Inc. v. State of Alaska, 1-JU-92-469 Civ. (the "Discovery Royalty Appeal"). Conoco claims in the Discovery Royalty Appeal that it is entitled to a five percent royalty on Schrader Bluff production from ADL 25906 located in the MPU for a period of 10 years by virtue of the discovery. The State claims that the G-1 well did not first discover oil in commercial quantities in the Schrader Bluff formation, and therefore Conoco is not entitled to a discovery royalty. The Discovery Royalty Appeal remains pending before the superior court.

6. On January 14, 1994, OXY requested DNR to partially substitute OXY as the real party in interest for an 8.81% working interest in ADL 25906 as Conoco's successor in interest. OXY represented

that it intended to file a motion to substitute or intervene in the Discovery Royalty Appeal. OXY's request remains pending before DNR.

Royalty Valuation Facts

7. On July 26, 1991, the State informed Conoco and OXY that it believed that they had been and were continuing to improperly value their production from the MPU for royalty purposes. The State asserted that Conoco and OXY had been and were continuing to pay royalties on the basis of the value received by them respectively, while the leases and MPU Agreement required them to pay on the basis of the higher of the value received by them or the volume weighted average received by other MPU lessees. By letters dated August 30, 1991, Conoco and OXY contended that paying royalties on the basis of the value received was correct because: (1) the State had acquiesced in this method; (2) the State had failed to comply with paragraph 18(h)(7) of the MPU Agreement; and (3) paragraph 18(h)(6)(c) of the MPU Agreement may be inoperative because the field prices reported by other lessees in the MPU may not have been "actually received" by those lessees. Until recently, this dispute ("Royalty Valuation Dispute"), which involves all oil production from the beginning of production to March 31, 1994 and thereafter, had been tolled during the parties' settlement negotiations.

8. On January 13, 1994, OXY notified the State that it was terminating the parties' tolling agreement relating to the Royalty Valuation Dispute effective March 13, 1994. On January 28, 1994, the State notified OXY that the State intended to determine which method in paragraph 18(h)(6) of the MPU Agreement shall be used to establish royalty value and requested OXY to present any evidence and argument regarding the matter. By letter dated February 28, 1994, OXY submitted written evidence and argument regarding the matter. The Commissioner has yet to make his determination on the matter.

Miscellaneous Facts

9. In December of 1993, Conoco agreed to assign all of its rights, title, and interest in the MPU leases and the MPU, to BP Exploration & Oil Inc. ("BP" will refer to BP Exploration & Oil Inc. and any

of its related persons or entities including, but not limited to, BP Exploration (Alaska) Inc.). The assignment was effective 11:59 p.m. on December 31, 1993.

10. Conoco, OXY, and the State desire to resolve and settle: (1) all claims involved in the Royalty Reduction Administrative Appeal, the Supreme Court Appeal, including the awards of cost and fees in the Contract Action and the Supreme Court Appeal, and the Discovery Royalty Appeal (collectively "Appeals"), and the Royalty Valuation Dispute, and (2) to provide a future valuation methodology and a future royalty reduction.

NOW, THEREFORE, for good and valuable consideration, the receipt of which is hereby acknowledged and in consideration of their mutual covenants and agreements expressed in this Agreement, the parties agree as follows:

1.0 SETTLEMENT

Conoco, OXY, and the State resolve and settle all claims which have been or could have been asserted in the Appeals and the Royalty Valuation Dispute for all leases in the MPU. The parties do not intend to settle and resolve other claims relating to royalty obligations including, but not limited to, pipeline tariff or quality bank adjustments.

2.0 RESOLUTION OF PAST DISPUTES

2.1 Offset

The parties agree that any amount which Conoco and OXY may owe the State as a result of the Royalty Valuation Dispute from the beginning of time to the production month ending midnight (A.S.T.) March 31, 1994 shall be offset against any amount which the State may owe Conoco and OXY as a result of the Appeals for the same period.

No party shall be liable to pay any other party any sum for any act, omission, over-payment or underpayment for any matter within the scope of the Mutual Release in Section 3.0 of this Agreement from the beginning of time to the production month ending midnight (A.S.T.) March 31, 1994.

2.2 Dismissal

Upon execution of this Agreement, Conoco, OXY, and the State shall file dismissals with prejudice of the Royalty Reduction Administrative Appeal and the Discovery Royalty Appeal. The stipulation shall be in the form provided in Exhibit 1 to this Agreement. Each party shall bear its own costs and attorney's fees in the Appeals. The debts created by the award of attorney's fees and costs to the State in the Contract Action and the award of attorney's fees in the Supreme Court Appeal are waived and discharged.

3.0 MUTUAL RELEASE

Except as otherwise provided in this Agreement, Conoco, OXY and the State hereby mutually release, acquit and forever discharge each other, from any and all claims, liabilities, responsibilities, disputes, obligations, demands and claims for relief, known or unknown that any party now owns or holds or has at any time heretofore owned or held, against another party arising out of or in any way connected with or related to the Appeals and Royalty Valuation Dispute. In this section, Conoco, OXY and the State include their respective assignees (including BP), predecessors, successors, parents, subsidiaries, affiliates, officials, officers, directors, agents, servants, employees, and attorneys.

4.0 FUTURE ROYALTY VALUATION

4.1 Methodology

For production after March 31, 1994, the methods for calculating royalty value in paragraph 18(h)(6) of the MPU Agreement and paragraphs 15 and 16 of the MPU leases are amended as set forth in this Agreement for OXY. The amended future methodology set forth in Sections 4.1-4.5 of this Agreement shall not apply to Conoco or its assignees, including BP.

For production after March 31, 1994, the "Future ANS Valuation Methodology for January 1992 Production Forward" set forth in Article III of the ANS Royalty Litigation Settlement Agreement between Exxon Corporation and the State ("Exxon ANS Royalty Settlement Agreement"), as amended from time-to-time, shall be the exclusive method for determining the per barrel "Royalty Value" of liquid hydrocarbons allocated to OXY from the MPU leases. For purposes of this Agreement, the term "liquid

hydrocarbons includes all hydrocarbons delivered to a LACT meter in liquid form, including what has been or may be described variously as oil, condensate, scrubber liquids, gas liquids, natural gas liquids, or NGLs. OXY's monthly per barrel Royalty Value for all liquid hydrocarbons from the MPU leases shall be the Royalty Value by Field from the Kuparuk River Unit computed under the Exxon ANS Royalty Settlement Agreement for West Coast placements, adjusted for the MPU quality differential, and the Milne Point and Kuparuk pipeline tariffs. Exhibit 2 is a hypothetical calculation of OXY's Royalty Value for the production month of January of 1994 as if the methodology had been in effect for that month. Attachment 1 of Exhibit 2 is the actual royalty report for January of 1994 showing the calculation by Exxon of its Kuparuk River Unit royalty value. Exxon's royalty value for the Kuparuk River Unit is found on Attachment 1 at the intersection of the horizontal line labelled "Crude" and column "h". Exxon's royalty value for the Kuparuk River Unit from Attachment 1 of Exhibit 2 is $6.560 per barrel for the production month of January of 1994. Adjusted for the MPU, OXY's illustrative Royalty Value for the MPU is $5.417 per barrel for the production month of January of 1994 as shown on Exhibit 2.

OXY and the State agree that it is both appropriate and reasonable to use the formula set forth in the Exxon ANS Royalty Settlement Agreement as adjusted for the Milne Point quality differential, and the Milne Point and Kuparuk pipeline tariffs, to determine OXY's royalty-in-value obligation. Therefore, OXY agrees to make, and the State agrees to accept in full satisfaction of OXY's royalty-in-value obligation, payments based exclusively upon the formula set forth in the Exxon ANS Royalty Settlement Agreement as adjusted for applicable quality differentials and pipeline tariffs.

4.2 Estimated Reports

The parties recognize that agreeing to use the Royalty Value from the Exxon ANS Royalty Settlement Agreement will make it impossible for OXY to calculate precisely its royalty obligation in the time required by the applicable lease terms. Because of that event, OXY must file estimated reports or take other action consistent with the applicable lease and unit agreement terms to ensure that its royalties are as accurately and timely paid as possible. Nothing in this Agreement relieves OXY of its obligation to correct

any royalty report which is filed incorrectly even if the error is due to an error by Exxon; provided, however, that OXY shall in no event be subject to any forfeiture (other than payment of interest) for failure to make timely or adequate payment where such failure results from OXY's lack of timely, complete or accurate information from the State whether attributable to error by Exxon or otherwise.

4.2.1 Exxon West Coast Deliveries

Within 10 days of receipt of Exxon's royalty reports, the State will provide OXY copies of royalty reports and amended royalty reports filed by Exxon for the Kuparuk River Unit. OXY must then revise its estimated report, pay any additional royalties due plus interest or take a credit plus interest, and submit the revision when its next royalty report is due.

4.2.2 Exxon Non-West Coast Deliveries

If Exxon reports a Royalty Value for oil delivered to destination markets other than the West Coast and disclosure to OXY of Exxon's West Coast Royalty Value is prohibited by law or by the confidentiality provisions of the Exxon ANS Royalty Settlement Agreement, then the following procedure shall apply:

a) OXY must file its estimated royalty report as provided above in this subparagraph 4.2.

b) Within 10 days of receipt of Exxon's royalty reports, the State will provide OXY a "blended" Royalty Value (which shall be defined as the volume weighted average Royalty Value for all of Exxon's deliveries to the various destination markets from the Kuparuk River Unit based on Exxon's royalty reports). The State will not provide OXY copies of Exxon's royalty reports.

c) If Exxon's blended Royalty Value, adjusted for the MPU quality differential and the Milne Point and Kuparuk pipeline tariffs, is greater than OXY's estimated Royalty Value, then OXY must revise its estimated report, pay any additional royalties due plus interest, and submit a revised report when its next royalty report is due. OXY's revised Royalty Value must equal or exceed Exxon's blended Royalty Value, adjusted for the MPU differential and the Milne Point and Kuparuk pipeline tariff.

d) Other than to correct mistakes made by OXY itself, to adjust the Royalty Value because of tariffs or quality bank adjustments, or to recalculate the Royalty Value as set forth in subparagraph 4.3, no additional revisions need be made to OXY's royalty reports until after the beginning of the fourth calendar year following the production month in question.

e) After the beginning of the fourth calendar year following the production month in question, the State shall provide OXY with Exxon's Royalty Value from the Kuparuk River Unit for West Coast placements for each month's production in the production year in question, and a recalculation of OXY's royalty obligation, plus interest, for each month of the production year in question based upon Exxon's royalty payments, including any adjustments. For example, in January of 1998, the State shall provide OXY with the Exxon Royalty Value from the Kuparuk River Unit for West Coast placements for each production month in 1994, and a recalculation of OXY's royalty obligation, plus interest, for each production month in 1994.

f) OXY must then revise its last filed royalty reports for the production months in question when its next royalty report is due. If OXY owes the State additional royalties as a result of the recalculation, OXY must pay the recalculation plus interest when its next royalty report is due. If the State owes OXY a refund of royalties as a result of the recalculation, the State must pay OXY, plus interest, by credit to OXY's next and, if necessary, succeeding royalty return(s).

g) OXY shall have the right, upon reasonable notice and with reasonable frequency, to audit all information in the possession of the State used to determine OXY's royalty obligations except information which cannot be disclosed by law or under the confidentiality provisions of Exxon's ANS Royalty Settlement Agreement. In addition, at any time after the beginning of the fourth calendar year and until the end of the sixth calendar year following the month in question (e.g., beginning January 1, 1998 and ending December 31, 2000, information for January 1994 and all other months of 1994 will be available to OXY), OXY shall have the right to audit per barrel transportation costs for Exxon (but not any underlying, detailed confidential data) of any applicable transportation costs between the Valdez terminus of TAPS and

the locations at which destination values were determined. In the event that the information necessary for the State to comply with Exxon's ANS Royalty Settlement Agreement or for OXY to audit transportation costs cannot be made available to OXY by law or under the confidentiality provisions of the Exxon ANS Royalty Settlement Agreement, the State and OXY will cooperate to arrange an exchange of the information (e.g., through a third party) which satisfies the State's obligations and OXY's rights to audit without violating the law or confidentiality provisions of the Exxon ANS Royalty Settlement Agreement.

It is the intent of the parties to make available for audit by OXY: (1) all data needed to audit the determination of applicable destination values, and (2) except for any detailed underlying confidential transportation data, all other data needed to audit the determination (as applicable) of (a) per barrel values at Valdez, (b) Trans Alaska Pipeline System (TAPS) and other pipeline tariffs, (c) gravity and other quality adjustments, (d) loss allowances upstream of Valdez, (e) per barrel values at TAPS Pump Station No. 1, and (f) field costs.

Nothing in this Agreement limits the State's rights under the Leases and applicable statutes and regulations to audit OXY's royalty returns and to adjust prior billings to OXY.

4.3 Intervention

OXY recognizes that the amended future methodology may from time to time change as a result of reopeners under the Exxon ANS Royalty Settlement Agreement.

This Agreement does not give OXY any independent right to intervene in any proceeding involving Exxon or any other ANS Royalty Litigation defendant. OXY does not have an independent right to invoke any of the provisions contained in Article IV of the Exxon ANS Royalty Settlement Agreement or other similar provisions in any settlement agreement which has been or may be entered into between the State and any other ANS Royalty Litigation defendant. If the royalty formula methodology set forth in the Exxon ANS Royalty Settlement Agreement is modified, a corresponding modification will be made in the values used to calculate OXY's royalty-in-value obligation retroactive to the production month or months affected by the modification to the Exxon formula methodology.

The following illustration demonstrates (without limiting) how the parties intend the modification procedure to work. If in March 1995, the Exxon ANS Royalty Settlement Agreement is modified to increase Exxon's monthly royalty-in-value obligation commencing January 1995, the Exxon modification would require recalculation of OXY's royalty-in-value obligations for the production months of January 1995, February 1995 and March 1995 by substituting Exxon's modified Kuparuk River Unit Royalty Value in the OXY royalty-in-value formula for these three months. The OXY royalty-in-value recalculation would be made in the production month immediately following OXY's receipt of Exxon's amended report based on the triggering modification (i.e., as applied to the illustration, the recalculation of OXY's royalty-in-value obligation and the filing of amended royalty reports would be made in April 1995, assuming OXY receives Exxon's amended report in March of 1995). In the event modification to the Exxon royalty-in-value formula is made by an arbitration panel, the appropriate recalculation shall be made in the production month following OXY's receipt of Exxon's amended report based on the final decision rendered by the arbitration panel. The State shall be responsible for timely notifying OXY of any and all modifications to or redeterminations under the State's settlement with Exxon.

4.4 Interest

The same interest rate shall apply for overpayments, underpayments and other obligations arising under this Agreement. Notwithstanding AS 38.05.135(d)-(e), the applicable interest rate shall be the prime rate of interest publicly announced by Bank of America, NT and SA, of San Francisco, California, from time to time, and that interest shall be compounded daily.

4.5 RIK and RIV Election

For production after March 31, 1994, the State may elect to take, either in-kind or in-value, all or a specified percentage or volume of its royalty interest in OXY's liquid hydrocarbon share from the MPU leases by giving 90 days advance written notice of its intent to OXY. Additionally, if necessary to implement this section, OXY will vote to amend the MPU Agreement and shall ask other MPU lessees to

agree to amend the MPU Agreement to provide for 90 days' notice. Nothing in this Section obligates OXY to obtain the agreement of other MPU lessees to amend the MPU Agreement.

5.0 FUTURE ROYALTY REDUCTION

5.1 Methodology

For production after March 31, 1994, the royalty rate specified in the MPU Agreement and ADLs 47432, 47433, 47434, 47437, 47438, 47439, 315846, and 319717 (collectively 20% Leases) is expressly amended for OXY only. The royalty rate for OXY's interest in the 20% Leases is reduced from twenty percent to twelve and a half percent. The royalty rate for all other OXY leases and other lessees in the MPU shall remain unchanged by this Agreement, but may be changed in the future as provided for in applicable statutes, regulations, and agreements. The amended future royalty rate and limitations set forth in Sections 5.1-5.3 of this Agreement shall not apply to Conoco or its assignees including BP and to OXY's assignees.

5.2 Assignment

The right to pay royalty based upon the methodology set out in Section 5.1 of this Agreement cannot be sold, assigned, cross-assigned, exchanged, or in any way transferred (collectively "Transfers"). If OXY Transfers in any manner any portion of its respective interests in the 20% Leases, the Transferee will have the obligation to pay royalty on the interest Transferred at the rate of twenty percent of the Royalty Value of gross production, as value is defined in Section 4.1.

5.3 Limits on Future Royalty Reduction

Notwithstanding paragraph 18(h)(8) of the MPU Agreement and any otherwise applicable law, OXY cannot apply for any reduced royalty: (1) for any of the leases identified in Section 5.1 of this Agreement, during the remaining life of the MPU; or (2) for any other liquid hydrocarbon production from the MPU, for five years from the effective date of this Agreement.

6.0 FUTURE DISCOVERY ROYALTY

As provided in Section 3.0 of this Agreement, Conoco and OXY release, acquit, and forever discharge the State from any past (retroactive) and future (prospective) discovery royalty relief respecting the formation variously known as the Shallow Oil Sands, West Sak Sands, and Schrader Bluff Formation at the MPU. As provided in Section 7.0 of this Agreement, Conoco and OXY warrant, each as to their respective and separate interests in the MPU as of the effective date of this Agreement, to the State that they have not assigned or transferred any portion of their discovery royalty claim to BP and that a release from BP need not be obtained for a complete (past and future) settlement of the Discovery Royalty Appeal.

7.0 INDEMNIFICATION AND WARRANTIES

Conoco, OXY (as to their own respective and separate interests in the MPU as of the effective date of this Agreement) and the State hereby warrant that they know of no other persons or entities from whom releases should be obtained for any of the claims, demands or causes of action settled by this Agreement and that they (as to their own respective and separate interests in the MPU as of the effective date of this Agreement) have not previously assigned or transferred, or purported to assign or transfer to any person or entity, any of these claims, demands or causes of action. Conoco and OXY (as to their own respective and separate interests in the MPU as of the effective date of this Agreement) specifically agree that they have not previously assigned or transferred to BP any past or future portion of the Discovery Royalty Appeal. Each party agrees to hold each other harmless from any and all liability, damages and costs incurred, including reasonable actual attorney fees if any other person or entity hereafter claims ownership or the right to prosecute the indemnifying party's separate and respective interest as of the effective date of this Agreement in any of the claims, demands or causes of action settled by this Agreement.

8.0 NO ADMISSION OF LIABILITY

Each of the parties acknowledges that this Agreement is solely for the purpose of settling disputed claims and that none of the parties hereby released admits any liability for, responsibility for, or the merits of any claims asserted by any other party.

9.0 FURTHER DOCUMENTS AND ACTS

Each party agrees, in good faith, to do all things necessary and convenient, to execute and deliver such additional documents and instruments, and to perform such additional acts as may be necessary or appropriate to effectuate, consummate or perform the terms and intent of this Agreement.

10.0 DISPUTES

This Agreement is made and entered into in the State of Alaska and shall be enforced under the internal laws of the State of Alaska. Any dispute regarding this Agreement shall be decided by the Director of the Division of Oil and Gas. Conoco and OXY shall have the right to present written evidence and argument to the Director. They shall not have the right to civil litigation-type discovery or a civil-litigation type trial with the right to call or cross-examine witnesses unless granted by the Director in his discretion. The Director shall issue written findings together with his determination regarding the relief that should be granted. Conoco and OXY shall have the right to appeal the Director's decision to the Commissioner. The record on appeal shall be limited to the record presented to the Director, but Conoco and OXY shall have the right to present additional written argument. The Commissioner's decision shall be subject to judicial review solely through the Alaska Rules of Appellate Procedure. The sole fact that the Commissioner is a signator to the Agreement or the State has a financial interest in the Agreement shall not be grounds for attacking any decision made by the Commissioner under this Section.

11.0 GENERAL PROVISIONS

11.1 Binding Effect

Except as provided elsewhere in this Agreement, this Agreement shall be binding upon each party and its representatives, successors and assignees, and shall inure to the benefit of each party and its representatives, successors or assigns.

11.2 Acknowledgement of Non-Reliance

Each of the parties acknowledges and agrees that no representation or promise not expressly contained in this Agreement has been made by any party or by its agents, employees, representatives or attorneys. Each of the parties further acknowledges that it is not entering into this Agreement on the basis

of any such promise or representation expressed or implied. All of the terms and conditions of this Agreement have been reflected upon without haste and no one is under a disadvantage. Each party has been represented throughout all the negotiations leading up to this Agreement by counsel of its choice.

11.3 Attorney Fees

If any legal action is brought for the enforcement of this Agreement, or because of an alleged dispute, breach, default or misrepresentation in connection with any of the provisions of this Agreement, the successful or prevailing party or parties shall be entitled to recover reasonable actual attorney fees and other costs incurred in connection with such action in addition to any other relief to which it or they may be entitled.

11.4 Captions

Any captions or headings of the sections of this Agreement are solely for the convenience of the parties, and are not part of this Agreement, or any provision of it.

11.5 Counterparts

This Agreement may be executed in one or more counterparts, each of which shall be deemed an original, and the counterparts shall constitute but one and the same instrument which may be sufficiently evidenced by one counterpart.

11.6 Declaration

Each of the parties hereby declares that the terms of this Agreement have been carefully read and are fully understood and are voluntarily accepted for the purpose of making full and final compromise, adjustment and settlement of any and all claims, disputed or otherwise described in Section 3.0 of this Agreement.

11.7 Entire Agreement

This Agreement constitutes the entire understanding between the parties with respect to the subject matter of this Agreement and supersedes all negotiations, prior discussions, and preliminary agreements.

12.0 NOTICES

Any notices under this Agreement shall be given by express mail, courier, or facsimile transmission to the designated representatives of the parties at the following addresses and facsimile numbers, or to such new representatives, addresses, and facsimile numbers as are designated in writing by the party making a change:

If to the State:

Commissioner of Natural Resources
400 Willoughby Avenue, Fifth Floor
Juneau, Alaska 99801-1724
Fax: (907) 586-2754

and

Director, Division of Oil and Gas
Box 107034
Anchorage, Alaska 99510-0734
Fax: (907) 562-5269 and 562-3852

If to Conoco:

Conoco Inc.
Legal Department
Attn: Managing Counsel
Exploration, Production & Natural Gas / North America Group
P.O. Box 4783
Houston, Texas 77210
Fax: (713) 293-3826

If to OXY:

Manager - Land, Western Region
OXY USA Inc.
P. O. Box 50250
Midland, Texas 79710
Fax: (915) 685-5931

EFFECTIVE as of December 30, 1993.

STATE OF ALASKA

By: _____
Commissioner of Natural Resources

Date Signed: _____

By: _____
Attorney General

Date Signed: _____

SUBSCRIBED AND SWORN TO before me this ____ day of _____, 1994.

_____
Notary Public, State of Alaska
My commission expires: _____

CONOCO INC.

By: _____

Title: _____

Date Signed: _____

SUBSCRIBED AND SWORN TO before me this ____ day of _____, 1994.

_____
Notary Public, State of _____
My commission expires: _____

OXY USA INC.

By: _____

Title: _____

Date Signed: _____

SUBSCRIBED AND SWORN TO before me this _____ day of _____, 1994.

_____
Notary Public. State of _____
My commission expires: _____

EFFECTIVE as of December 30. 1993.

STATE OF ALASKA

By: _____
Commissioner of Natural Resources

Date Signed: 7/12/94

By: _____
Attorney General

Date Signed: 12 July 1994

SUBSCRIBED AND SWORN TO before me this 12th day of July, 1994.

_____
Notary Public. State of Alaska
My commission expires: 6-14-97

CONOCO INC.

By: _____

Title: _____

Date Signed: _____

SUBSCRIBED AND SWORN TO before me this ____ day of _____, 1994.

_____
Notary Public. State of _____
My commission expires: _____

OXY USA INC.

By: _____

Title: _____

Date Signed: _____

EFFECTIVE as of December 30, 1993.

STATE OF ALASKA

By: _____
Commissioner of Natural Resources

Date Signed: _____

By: _____
Attorney General

Date Signed: _____

SUBSCRIBED AND SWORN TO before me this ____ day of _____, 1994.

_____
Notary Public, State of Alaska
My commission expires: _____

CONOCO INC.

By: _____

Title: _____

Date Signed: _____

SUBSCRIBED AND SWORN TO before me this ____ day of _____, 1994.

_____
Notary Public, State of _____
My commission expires: _____

OXY USA INC.

By: _____

Title: Attorney-in-fact

Date Signed: 7/8/94

SUBSCRIBED AND SWORN TO before me this 8th day of July, 1994.

Notary Public, State of Texas
My commission expires: 12/9/96



EFFECTIVE as of December 30, 1993.

STATE OF ALASKA

By: _____
Commissioner of Natural Resources

Date Signed: _____

By: _____
Attorney General

Date Signed: _____

SUBSCRIBED AND SWORN TO before me this ____ day of _____, 1994.

_____
Notary Public, State of Alaska
My commission expires: _____

CONOCO INC.

HAG By: L. T Brooks

Title: ATTORNEY-IN-FACT

Date Signed: 7/19/94

SUBSCRIBED AND SWORN TO before me this 19 day of JULY, 1994.

Kimberly Elizabeth Miller
Notary Public
Lafayette Parish, Louisiana
My Commission is For Life

Kimberly Elizabeth Miller
Notary Public, State of LOUISIANA
My commission expires: with life

OXY USA INC.

By: _____

Title: _____

Date Signed: _____

ENCLOSURE 8

IN THE SUPERIOR COURT FOR THE STATE OF ALASKA

THIRD JUDICIAL DISTRICT AT ANCHORAGE

CONOCO, Inc., a Delaware corporation and OXY USA INC., A Deleware corporation Appellant, vs. STATE OF ALASKA, DEPT. OF NATURAL RESOURCES, Appellee.	Nos. 1JU-91-797 Civ. and 1 JU-91-798 Civ. (consolidated)

STIPULATION FOR DISMISSAL WITH PREJUDICE AND ORDER THEREON

Pursuant to a Settlement Agreement dated, December 30, 1993, the parties, by and through their respective counsel, stipulate that this matter shall be dismissed with prejudice. Each side shall bear its own costs and attorney's fees.

BRUCE M. BOTELHO
ATTORNEY GENERAL

DATED: 7-13-94 By: Patrick J Coughlin
Patrick J. Coughlin
Assistant Attorney General

BIRCH, HORTON, BITTNER & CHEROT

DATED: 7/25/94 By: _____
Jonathon K. Tillinghast

FILED IN THE TRIAL COURTS
STATE OF ALASKA, FIRST DISTRICT
AT JUNEAU

JUL 28 1994

Clerk of Court

By _____ Deputy

ORDER

IT IS SO ORDERED.

DATED: July 25, 1994.

Hon. Larry R. Weeks
Superior Court Judge

I certify that on 7/26/94 copies of the foregoing were sent to Jonathon K. Tillinghast and Patrick J. Coughlin
BY: Anne Worth
Secretary to Judge Carpeneti

DEPARTMENT OF LAW
OFFICE OF THE ATTORNEY GENERAL
ANCHORAGE BRANCH
1031 W. FOURTH AVENUE, SUITE 200
ANCHORAGE, ALASKA 99501
PHONE: (907) 269-5100

Enclosure 8

ENCLOSURE 9

September 19, 1979

Mr. Felix Nigh
Conoco, Inc.
Unit Operator
Proposed Gwydyr Bay and Milne Point Units
3 Greenway Plaza East, Suite 2928
Houston, Texas 77046

Dear Mr. Nigh:

I have considered your requests for establishment of the Gwydyr Bay and Milne Point Units, and Director Tom Cook's recommendation regarding those units. As you are undoubtedly aware, these unit proposals have also produced other recommendations to me from the public and most notably from the House Interim Committee on Oil and Gas Leasing Policy, which I must also consider in making a determination that protects the best interests of the State of Alaska.

Review of all the facts and recommendations before me has convinced me that the facts as they exist today make it contrary to the public interest to approve the units as proposed. By the same token, principles of equity and fair expectations clearly indicate that simple rejection of the units, which would result in expiration of most existing leases, is similarly not in the public interest, even though it has been recommended by the legislative committee.

The arguments against approval of these units as proposed center around three points. First, the fact that both statutory and regulatory standards for oil and gas leases have changed in the past 10 years, is clear to all. Second, it is equally clear that a committee of the Alaska Legislature desires to deal much more specifically than is presently the case with unitization principles and procedures, and would prefer that no open-ended units are approved pending such consideration. While the interim committee cannot speak for the entire legislature, it is obvious that the committee reflects the sentiment of a definite segment of the State's population. Third, the economics of oil and gas leasing have changed so drastically within the past ten years that in order to effectively protect the State's interest, certain changes in the leases are necessary.

Enclosure 9

Accordingly, I suggest it would be both in the State's interest and in your interest if we agreed upon a two-year unit approval, with some modifications to leases that would otherwise expire.

In order to approve the Gwydyr Bay and Milne Point Units for this time period, I am exercising my authority under AS 38.05.180 and Section 32 of the lease in requesting your consent for the following changes, which I find necessary and proper to secure protection of the public interest:

1. Increase annual rental and minimum royalty payments to the present standard of $3.00 per acre, as enacted in AS 38.05.180(n); all leases proposed for inclusion in the units will conform to this standard except those presently held by their own terms.

2. Increase royalty share to one-fifth (20%), which is our present minimum standard, as used in the recent Copper River Basin lease sale. This higher royalty will apply to all leases proposed for inclusion in the units except those presently held by their own terms.

3. Apply the present standard of lease stipulations, which are attached. These generally reflect the stipulations which we will use in the upcoming Beaufort Sea lease sale. All leases in the units will be subject to these stipulations.

4. Modify the existing leases to eliminate the problem presently under litigation in State v. Amerada Hess, et al. This modification will apply to all leases in the units.

The drilling requirements set out in Sections 9 and 10 of the proposed Gwydyr Bay and Milne Point Unit Agreements will be accepted in their currently proposed form.

Specific language to incorporate these changes into the proposed unit agreement is attached.

I am sure you will agree that upgrading your present leases to today's standards is a reasonable request in exchange for a two-year extension of the lease term, in light of major changes in circumstances since 1969. I sincerely hope we can reach agreement on this matter before expiration of the affected leases.

Sincerely,

Robert E. LeResche
Commissioner

REL:blg

ENCLOSURE 10

BILL SHEFFIELD, GOVERNOR

DEPARTMENT OF NATURAL RESOURCES

DIVISION OF OIL AND GAS

POUCH 7 034
ANCHORAGE, ALASKA 99510

October 9, 1984

H. D. Haley
Conoco, Inc.
2525 C Street, Suite 100
Anchorage, Alaska 99503

Re: Royalty reduction request
for Milne Point.

Dear Mr. Haley:

This letter responds to your October 4, 1983 letter in which Conoco Inc. requested a royalty reduction for the following State of Alaska leases: ADL 47432, ADL 47433, ADL 47434, ADL 47437, ADL 47438, ADL 47439, ADL 315846, and ADL 319717 ("the Conoco leases"). Due to the legal, economic and geologic considerations stated below, the Division of Oil and Gas has determined that Conoco's request must be denied.

Although we can appreciate the difficulties Conoco anticipates in profitably developing Milne Point production, the division is statutorily prohibited from granting the requested royalty reduction. AS 38.05.180(j) precludes the division from granting a royalty reduction until there has been two years' initial production from the field. In Conoco's request, you relied on certain contractual provisions as support for the requested royalty reduction. However, the Department of Law has advised us that those contractual provisions were mooted by the 1979 unit agreement covering the Conoco leases, and that the statutory restriction is applicable. Under the pertinent geologic and economic considerations, Milne Point must be regarded as a separate field for royalty reduction purposes. Since there has not been two years' initial production from the Milne Point Field, the division is statutorily prohibited from granting Conoco a royalty reduction. A more detailed discussion of these conclusions follows.

Enclosure 10

EXHIBIT 1

A. Legal Considerations

The division has considered the contractual and regulatory provisions stated in Conoco's royalty reduction request, and has determined that those contractual provisions were superseded by the September 28, 1979 "Unit Agreement for the Development and Operation of the Milne Point Unit." That unit agreement expressly provides that its terms modify Conoco's prior leases, and expressly precludes the state from granting royalty reductions for covered leases until two years' production occurs from the field in which the lease is located. In 1978 the Alaska legislature had amended the royalty reduction statute, AS 38.05.180(j), to require two years' initial production from the field before the commissioner of natural resources could even consider granting a royalty reduction request. The unit agreement requirement brought the Conoco leases into conformity with that amended statute. Neither the statute nor the unit agreement provisions need be belaborred here since they are treated at length in the April 24, 1984 memorandum of advice from Assistant Attorney General Bonnie Thie to the division. (Attached as Exhibit A)

The threshold questions are whether the Milne Point leases are located in a discrete field, and if so, whether there has been two years' initial production from the field in which the Milne Point leases are located. Although the division has no statutory definition of "field" for royalty reduction purposes, the memorandum of advice states three possible geologic definitions of field: (1) a common source of supply, pool or reservoir; (2) multiple reservoirs vertically separated; or (3) multiple, partially overlapping individual reservoirs like those created in a depositional environment such as a river delta. The memorandum of advice further delineates the legislative policies to be considered in applying those geologic definitions: (1) the policy of reducing royalties when necessary to ensure that economic pressures would not cause an oil and gas field to be prematurely abandoned as production begins to decline, and (2) the countervailing policy of preventing speculative royalty bidding, in which a firm would make an unrealistically high bid to secure a lease while counting on a subsequent royalty reduction to make development of the lease profitable. The memorandum of advice concludes that the division must apply its expertise to those geologic, economic, and policy issues to determine both the scope of the Milne Point Field and whether two years' production has occurred from the Milne Point Field.

B. Geologic Considerations

Conoco's counsel has suggested that for purposes of Conoco's royalty reduction request, the Milne Point leases be considered as part of the Kuparuk Field. However, under each of the three geologic definitions of field identified in the memorandum of advice as being most pertinent to royalty reductions, Conoco's Milne Point Unit constitutes a field separate from the Kuparuk Field. A technical review of the subsurface geology, regional stratigraphic data, and the reservoir characteristics of the productive formation in the Kuparuk and Milne Point Units confirms that the Milne Point leases will produce from an accumulation separate and distinct from that which is productive in the Kuparuk River Unit.

Petroleum occurs in several stratigraphic intervals in both the Milne Point Unit and the Kuparuk River Unit. However, petroleum production from the Kuparuk River Unit to date in commercial quantities has been limited to production from the Kuparuk Formation, as that formation was formalized by George J. Carman and Peter Hardwick, Geology and Regional Setting of Kuparuk Oil Field, Alaska, 1983 AAPG Bulletin, V. 67, p. 1014-31. With the exception of a pilot project in the stratigraphically higher West Sak Sands, none of the other stratigraphic intervals known to contain petroleum regionally, the Sadlerochit Formation, the Lisburne Formation and the Kekiktuk Formation, have yet produced hydrocarbons in commercial quantities in either the Kuparuk or the Milne Point Unit areas. Since Conoco proposes to develop and produce only Kuparuk Formation reserves in the Milne Point Unit, only the stratigraphic setting and structural configuration of the Kuparuk Formation itself need be considered.

Carman and Hardwick informally subdivided the Kuparuk Formation's stratigraphic sequence into an upper and a lower member. They further divided the lower member into the "A" and "B" units, and the upper member into the "C" and "D" units (see attached Figure 1). The Kuparuk Formation is thought to have been deposited in a shallow marine environment, and its various stratigraphic units are generally laterally continuous. However, reservoir quality unit "C" is absent at Milne Point. Under Conoco's current proposal, the Milne Point Unit will produce only from the "A" and "B" units, while the Kuparuk River unit produces predominantly from the "A" and "C" units.

Three possible geologic definitions of "field" are most pertinent for royalty reduction purposes. "Field" may refer (1) to a common source or supply, pool, or reservoir; (2) to multiple reservoirs vertically separated; or (3) to multiple, partially overlapping individual reservoirs like those created in a

depositional environment such as a river delta. In reviewing whether Conoco's leases lie within the same field as the Kuparuk River Unit leases, the division considered each of these possible definitions. The second and third definitions may be briefly dismissed since they do not apply to the geographic and geologic parameters of the Kuparuk Formation in the Milne Point and Kuparuk River Unit areas. The Kuparuk River Unit and the Milne Point Unit could not be regarded as one field under the second definition, that of vertically separated reservoirs, because the two units do not share a common surface area. Although the units are both located over the Kuparuk Formation, they are geographically separated, with the Milne Point Unit located to the northeast of the Kuparuk River Unit. Nor could the two areas be described as comprising the same field under the third definition, that of multiple, partially overlapping individual reservoirs like those created in a depositional environment such as a river delta. The Kuparuk Formation consists of generally laterally-continuous units deposited in a shallow marine environment.

The "A" unit of the Kuparuk Formation is potentially productive in both the Kuparuk River and Milne Point Unit areas, making the first definition of field, a common source of supply, pool or reservoir, possibly applicable. However, to satisfy that definition, structural and stratigraphic continuity must exist between the Kuparuk River and Milne Point Unit accumulations. If either a structural barrier, due to folding or faulting, or a stratigraphic barrier, due to the absence of a continuous permeable bed, exists between the two accumulations, they can not be described as the same field.

Published data confirm the existence of a discrete Milne Point Field structurally distinct from the Kuparuk River Field. The Carman and Hardwick study describes a structural dip closure along the northern and eastern flanks of the Kuparuk Field. The lower half of attached Figure 2, taken from that study, demonstrates how a combination of folding and faulting have resulted in a separate Kuparuk Field hydrocarbon accumulation. The northeast border of the Kuparuk Field is delineated by an oil-water contact located southwest of the Milne Point Unit. The top half of Figure 2 shows the Socal Simpson Lagoon 32-14 Well (dry hole) and the abandoned ARCO West Sak 25 Well, with the oil-water contact of the Kuparuk Field located to the southwest. Based on data from those wells, the Milne Point Field oil-water contact appears to lie to the northeast. The oil-water contact on the northeast side of the Kuparuk Field is also shown on the attached Figure 3, a structure contour map submitted by ARCO

Alaska, Inc., operator of the Kuparuk River Unit. On this map, the oil-water contact is placed at approximately minus 6450 feet subsea, similar to the location shown in Figure 2.

Other public and confidential data on file with the division similarly demonstrate structural discontinuity between the Kuparuk and Milne Point accumulations. Separate oil-water contacts exist for each field, with the drainage pattern between the two fields being northeastward in the case of the southwestern edge of the Milne Point Field, and southwestward in the case of the northeastern edge of the Kuparuk Field. There exists an intervening structural discontinuity between the areas so extensive as to prevent a common source of supply, pool, or reservoir. Thus, the Kuparuk River and Milne Point Units contain two separate and distinct fields, even though the "A" unit is potentially productive in both areas.

Available geological data support the conclusion that the Milne Point Field and the Kuparuk Field contain separate accumulations of hydrocarbons. Under the relevant geologic considerations, the Conoco Milne Point Unit leases are not within the same field as the Kuparuk River Unit leases.

C. Economic Considerations

The determination of whether Conoco's Milne Point Unit leases could at this time legally receive a royalty reduction must be made in light of legislative intent to prevent premature abandonment of producing fields and to preserve the integrity of royalty bidding. Specifically, the memorandum of advice instructs the division to consider ". . . whether the Legislature's objectives will be met if there is no production history or cost data from an area linked by geology or economics to the applicant lease (e.g., shared cost, geologic and engineering data); whether reducing the royalty on oil or gas from one area produced independently of another area will prolong the production life of the other area; and whether, if there had been royalty bidding, reducing the royalty under the instant circumstances would make a sham of that bidding."

The legislative policy of preventing early abandonment of a producing field cannot be met if there is no demonstration by the applicant that the costs of continued production exceed a "reasonable" rate of return on the lessee's discounted investment. Conoco's costs to develop the Milne Point Unit leases cannot be determined directly from the costs ARCO incurred in developing the Kuparuk River Unit leases. Since the major

production from each field occurs from different horizons within the same stratigraphic interval, the formation characteristics and the anticipated producing rates can be expected to vary. In recognition of this fact, the scale of development for each field is unique to that field. The Milne Point Field reserve size is much smaller than the Kuparuk Field reserve size. Accordingly, the investment required by Conoco to fabricate and install production facilities at Milne Point is but a fraction of the costs associated with developing the Kuparuk Field. Moreover, the rates of return which may be "profitable" to ARCO or its partners in the Kuparuk Field provide little, if any, indication of what may be profitable to Conoco and the other working interest owners in the Milne Point Field.

Whether Conoco can operate the Milne Point Field profitably can only be demonstrated retrospectively after Conoco installs production and transportation facilities and commences production at Milne Point. Conoco can speculate as to its future successes or failures, but the legislature clearly contemplated that the department would consider more than the lessee's prognostications (based on a third party's performance in dissimilar circumstances) in determining whether or not to grant a royalty reduction. Similarly, absent a history of production, there is no basis for making an argument that reducing the royalty rate on the Kuparuk leases would prolong the production life of the Milne Point leases, or vice versa.

The legislative policy against allowing royalty reductions in circumstances where the royalty reduction would make a sham of royalty bidding would also be contravened if the division granted Conoco's request. To grant the requested royalty reduction despite Conoco's lack of sufficient production and cost data would make a sham of royalty bidding, because, in essence, Conoco did "bid" the 20 percent royalty rates for those leases for which it is now requesting a reduction. The leases in question were nearing the expiration of their primary terms in 1979 when Conoco requested that they be combined to establish the Milne Point Unit, thus extending their primary term and enabling Conoco and its partners to pursue a delineation drilling program. Each of the original leases provided for a royalty rate of 12.5 percent. As one of the conditions of committing those leases which would not otherwise have been held by their own terms, former Commissioner of Natural Resources LeResche increased the lease royalty obligations to 20 percent. Conoco and all the other potential working interest owners had the option at that time to refuse the royalty increase and to allow the leases to expire. ARCO, for example, chose not to join the unit as a consequence of this requirement. Conoco, however, agreed both to

the royalty increase and to other modifications of the original lease terms. Conoco then formed the Milne Point Unit and began an aggressive delineation and development program.

By agreeing to the increased royalties imposed as a condition to the lease term extensions, Conoco was allowed to retain what were then suspected to be extremely valuable leases without having to compete openly with other knowledgeable companies for that privilege. In 1979, two of the leases proposed for commitment to the Milne Point Unit contained wells certified by the department as capable of producing in paying quantities. Had Conoco allowed the Milne Point leases to expire, the department would have reoffered the leases, presumably under a royalty or net profit share bidding system or with a higher fixed royalty, and Conoco would have been forced to compete with other potential lessees to acquire the new leases. Conoco agreed to the increased royalty with full knowledge of the commerciality of the certified wells and with perhaps the best knowledge then available of the development requirements for the reservoirs. In light of these circumstances, it would seem both unfair to other potential lessees and irresponsible on behalf of the department to grant the requested royalty reduction without an unequivocal showing by Conoco that Milne Point development will not be economically feasible absent a royalty reduction. This showing can only be made when there are sufficient production and cost data for the department to evaluate.

not likely!

D. Conclusion

Both the economic and the geologic considerations pertinent to the division's evaluation of Conoco's royalty reduction request show the existence of a Milne Point Field that is discrete from the Kuparuk Field for royalty reduction purposes. Conoco accepted the current 20 percent royalty in order to retain its Milne Point leases, and the profitability of Conoco's Milne Point development cannot be determined by reviewing Kuparuk Field development costs. To grant Conoco a royalty reduction request at this time would thus violate the legislative policy against speculative royalty bidding and would not advance the legislative policy of preventing premature abandonment of producing fields. The underlying geology also supports the division's determination that the Milne Point Field is discrete from the Kuparuk Field, showing two distinct accumulations within a larger geologic formation.

Since the Milne Point Field is separate from the Kuparuk Field, the Commissioner is statutorily prohibited from

granting Conoco's royalty reduction request until after two years' initial production from the Milne Point Field itself. The division's decision is based on a consideration of the currently available economic and geologic data. If Conoco wishes to pursue its royalty reduction request further, it is, of course, entitled to apply formally for royalty reduction under 11 AAC 83.185. Upon Conoco's fulfillment of the requirements of subsection .185(a), the Commissioner will schedule a public hearing at which Conoco can present further information and evidence. If you have any questions concerning this letter, please feel free to contact me.

Kay Brown, Director
Division of Oil and Gas

Enclosures

ENCLOSURE 11