

ALASKA LEGISLATURE SPECIAL COMMITTEE/SUBJECT FILES 8672

2327 SCOMM 96: HOUSE SPEC. COMM. ON OIL & GAS, 1995-1996

STAT
DEPARTMENT

DEL. 2-5-96 LOCATION Oil: Gas
FROM 1010 W 131st LOCATION
TELEPHONE/TELECOM # _____ TOTAL NUMBER OF PAGES 5
TRANSMITTING CH/SPEED _____ DATE 2-5-96 TIME _____
PHONE FOR PROBLEMS/NAME/NUMBER 515-240
COMMENTS _____

February 5, 1986

Mr. John R. Kemp
Manager of Alaskan Operations
Conoco Inc.
3201 C Street, Suite 200
Anchorage, AK 99503

Re: Milne Point Unit Agreement

Dear Mr. Kemp:

Since your company filed its applications for royalty relief for the Milne Point Unit on November 4, 1985, we have discussed the issues involved on a number of occasions. I am aware of your strong perception that royalty relief is essential for further development and continued production of the Milne Point field. I am writing to suggest an alternative to the proposals presented in your royalty relief applications; our proposal would entail a royalty alteration and Conoco's guarantee for payment as opposed to a royalty reduction.

The State is very much interested in promoting development and production of marginal oil and gas fields in Alaska. However, despite any marginal nature of operations at Milne Point, my review and analysis of your applications so far have shown no clear statutory authority for granting Conoco a simple and straightforward reduction in royalty at this time.

For example, you requested that I reconsider the State's 1979 decision to condition unitization of the Milne Point field on an increase of the royalty on the Conoco leases to twenty percent. This would require me to waive a regulation which limits reconsideration to a thirty-day period following the initial decision. My interpretation of the authority cited in your application indicates that I am empowered to waive that regulation only when the interests of justice require the waiver. I would not be prepared to make that determination until after conducting a thorough review of both the entire set of circumstances of the ensuing unitization decision and the unit activities since that time.

Enclosure 11

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Over the life of the field, equivalent or greater overall royalty payments will accrue to the State as a result of the royalty alteration I am proposing. However, the change also should give Conoco strong encouragement to further develop

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5. It is understood that this royalty alteration, if approved, would not preclude Conoco or any of its leasehold partners from making future applications for royalty reduction or alteration. If such application was filed by Conoco and approved by the State, the specific royalty guarantee made part of this agreement would terminate as to production prospective to the effective date of any new agreement.

ENCLOSURE 12

STATE OF ALASKA

DEPARTMENT OF NATURAL RESOURCES

OFFICE OF THE COMMISSIONER

STEVE COWPER, GOVERNOR

400 WILLOUGHBY AVE.
JUNEAU, ALASKA 99801-1779
PHONE: (907) 465-2400

April 29, 1987

Mr. Tom Painter
Division Manager
Conoco, Inc.
3201 C Street
Suite 200
Anchorage, AK 99503

Dear Mr. Painter:

As you requested in your April 20, 1987 letter to me, I am writing to inform you of my decision regarding whether the department has the statutory authority to grant a reduction in its royalty on production from the Milne Point Unit in November, 1987.

My staff and I have reviewed both the applicable statutes and the history of production at the Milne Point field carefully. In addition, we have conferred with Assistant Attorney General Steve Porter who has conducted a review of the legislative history, the statutes and the case law on our behalf. Based upon that review, I have concluded that I do not have the authority to approve a request to reduce royalty rates until after two years of production from the Milne Point Unit has occurred.

Although November, 1987 represents the two-year anniversary of the commencement of production from the Milne Point Unit, two years of initial production will not have occurred by that time. My reading of the statutes confirms that there must be two years of actual production to form the basis for the economic review which must precede and support any decision to reduce the royalty rate for a producing field. Thus, the two-year period of initial production for the Milne Point Unit is tolled during the period production is suspended, as is currently the case.

Staff from the Division of Oil and Gas concur with Conoco's economic assessment of the losses incurred by continued production at Milne Point. They agree that had those losses been experienced over a two-year production history, a royalty reduction would be advisable. On the basis of their

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Enclosure 12

10-9614

Mr. Tom Painter

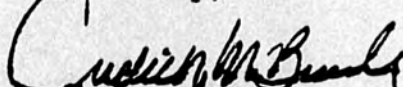
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April 29, 1987

analysis I remain sympathetic to Conoco's dilemma. However, the department's options are limited under the statutes, and a royalty reduction at this time is not possible.

If you have any additional questions or are interested in discussing other options which might be available, please feel free to call me.

Sincerely,



Judith M. Brady
Commissioner

ENCLOSURE 12-A

12 A

MEMORANDUM

DEPARTMENT OF NATURAL RESOURCES
DIVISION OF MINERALS AND ENERGY MANAGEMENT

State of Alaska

TO: Distribution List

DATE: September 1, 1982

FILE NO:

TELEPHONE NO:

FROM: Mary Weisenberger *mkw*
Land Management Officer
for Kay Brown
Director

SUBJECT: NORTH TRADING BAY FIELD
APPLICATION FOR ROYALTY
REDUCTION BY TEXACO
ADL 17597

Attached is an application by Texaco for a reduction of royalty to five percent (5%) on oil and gas lease ADL 17597, within the North Trading Bay Unit. The application was given to Kay at a meeting with Texaco representatives on August 25.

Texaco's application is not complete because they have not provided the information required by 11 AAC 83.665(4), which states that the application must 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.

When the necessary information is supplied, you will receive a copy. The current information is being provided to enable you to make a preliminary review.

Distribution:

James Eason ✓
William Van Dyke
Sam Murray
Edward Park

Enclosure 12A

AGO 234991



LOS ANGELES DIVISION
LAND DEPARTMENT

PETROLEUM PRODUCTS

TEXACO
U.S.A.
A DIVISION OF TEXACO INC.
3350 WILSHIRE BOULEVARD
P.O. BOX 3758
LOS ANGELES, CA 90061
213-739-7100

August 20, 1982

#215699: ADL 17597
NORTH TRADING BAY FIELD - ALASKA

Department of Natural Resources
Pouch M
Juneau, Alaska 99811

Attention: Mr. John Katz, Commissioner

Gentlemen:

Texaco Inc. respectfully requests a reduction of royalty on the Texaco-Superior Platform "A" wells located in the North Trading Bay Field in the Cook Inlet. The Alaska Statutes, 38.05.180 (j), provide for this reduction for the purpose of prolonging the economic life of an oil and/or gas field to compensate for the increasing costs in the later stages of production decline. Such is the case with the wells producing from Platform "A" on the lands within oil and gas lease ADL 17597, located in Township 10 North, Range 13 West, Seward Meridian, Sections 14, 15, 22, 23, 27, 28, 33 and 34.

The information in the attached Exhibit "A" clearly shows the revenue from the producing portion of the subject lease is insufficient to produce a reasonable rate of return with respect to our total investment in the lease.

Platform "A" was installed in April, 1968 and the drilling phase was completed in November, 1969. There are no plans at this time for any additional drilling. The initial production was about 5,000 barrels of oil per day from eight wells.

At the present time two wells are shut in (T/S #8 and #9), two wells are on Reda pumps (T/S #1 and #2), three wells are on gas lift (T/S #4, #6 and #7), and one well has been converted to a gas well (T/S #3).

The total production for the first six months of 1982 was 44,159 barrels of oil and 135,656 barrels of water. The production for July was 8,794 barrels of oil and 28,426 barrels of water.

August 20, 1982

The production for each month is as follows:

<u>MONTH</u>	<u>BBLS. OF OIL</u>	<u>BBLS. OF WATER</u>
January, 1982	12,361	26,048
February, 1982	6,125	12,951
March, 1982	2,874	13,624
April, 1982	6,448	23,381
May, 1982	9,298	34,112
June, 1982	7,053	25,540

Consequently, Texaco hereby requests that the royalty rate of 12½ percent on subject lease be reduced to a rate of 5 percent in order to attempt to prolong the economic life of this lease.

Enclosed is the filing fee of \$20.00 required by Section 11 AAC 88.105(7) and Texaco agrees to defray the costs of publishing the notice required by Section 11 AAC 83.185(b) of the leasing regulations.

Any notice relative to our application for royalty relief may be sent to Texaco Inc., 3350 Wilshire Blvd., Los Angeles, CA 90010, Attention: Division Land Manager. If there are any questions or any additional information needed, please contact the undersigned at Area Code 907, 278-9611.

Very truly yours,

TEXACO Inc.

Ethel H. Nelson

Ethel H. Nelson

Advanced Exploration Land Representative

EHN:bjs

Enclosure

EXHIBIT "A"

PLATFORM "A" COOK INLET ALASKA
COST, EARNINGS, AND PRODUCTION

<u>YEAR</u>	<u>GROSS W.I. BBLs</u>	<u>GROSS EARNINGS</u>	<u>GROSS OPR. COST</u>	<u>NET EARNINGS</u>
1978	159,466	\$1,202,298	\$ 938,174	\$264,124
1979	154,322	1,813,108	3,423,790	-1,610,682
1980*	136,212	1,711,176	1,864,502	- 153,326
1981*	120,218	3,426,298	2,709,098	717,200
1982* (6 mos.)	45,148	1,403,520	1,688,122	- 284,602

*This data includes Windfall Profits Tax

BJC
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8-20-82

AGU 234 994

ENCLOSURE 13



BP EXPLORATION
Exploration Department

RECEIVED

DEC 08 1994

DIVISION OF OIL & GAS

BP Exploration (Alaska) Inc.
900 East Benson Boulevard
P.O. Box 196612
Anchorage, Alaska 99519-6612
(907) 561-6111

December 6, 1994

Mr. James E. Eason, Director
Alaska Department of Natural Resources
Division of Oil and Gas
3901 C Street, Suite 1380
Anchorage, AK 99502

Subject: Badami Unitization

Dear Mr. Eason:

Further to our meeting with you on November 29, 1994, BP wishes to express for the record its utmost disappointment that we were, jointly, unable to identify an appropriate way forward to unitize the proposed Badami development area.

We firmly believe that unitization of the Badami area is absolutely essential to moving the prospect closer to development, protect natural resources and the environment and serve the State's best interest. Hence, we were very discouraged that you expressed an unwillingness to work closely with us, in a cooperative spirit, to facilitate unitization and development in the area. We truly believed that a new relationship, between industry and the DNR, had been emerging and to this end we have been working very closely with your staff for the past 12 months. (Note: Our original unit application was submitted on January 21, 1994 and revised September 9, 1994. It was withdrawn and a new application submitted on November 18, 1994.) The dialogue to date has been very open, constructive and encouraging and we believed our latest submission to you conformed to the guidance of your department which we received on numerous occasions. We were therefore astonished when we found out that you disagreed with the fundamental issue of whether Badami should or could be unitized.

Furthermore, we fully expected to discuss and clarify questions and concerns about the specifics of the Plan of Exploration or our sliding scale royalty proposal. We did not expect to encounter such a fundamental objection after the many months of cooperation, encouragement and discussion with your staff on technical and legal issues. Based on your response we will have to take a very close look at our work program in the area and question the wisdom of progressing the project at this time, while the DNR Director appears to be in the mode of discouraging prudent development. In the interim we will expand and clarify our arguments supporting formation of the Badami Unit even though you

Letter - J. Eason, DNR
Re: Badami Unitization
December 6, 1994
Page 2 of 2

offered no encouragement and thought there would be a small chance of gaining your support.

We remain convinced of the mutual benefit in pursuing Badami unitization and hope that you will see the benefits of working this issue jointly, to help us find a way to remove uncertainty from the lessor/lessee relationship. If you have any questions concerning this letter or wish to suggest a way forward, please call me at 564-5989.

Yours sincerely,

E.P. Zelnick, Jr. for T.J. Obeney
T.J. Obeney
Manager, New Developments, Alaska

TJO:lbs.

ENCLOSURE 14

TONY KNOWLES, GOVERNOR

DEPT. OF NATURAL RESOURCES

DIVISION OF OIL AND GAS

P.O. BOX 107034
ANCHORAGE, ALASKA 99510-7034
PHONE (907) 787-2553

December 9, 1994

Mr. T. J. Obeney
Manager, New Developments, Alaska
B.P. Exploration (Alaska) Inc.
900 East Benson Boulevard
P. O. Box 196612
Anchorage, Alaska 99519-6612

Dear Mr. Obeney:

I am responding to your December 6, 1994 letter regarding the proposed Badami Unit. In all honesty, I find it difficult to know just where to begin. While short on specific, constructive responses to the questions I posed during our recent meeting, your letter is long on *ad hominem* attacks and mischaracterizations of my position. To the extent that those may have been occasioned by your misunderstanding either my comments regarding the proposed application, my requests of you for further justification of your proposal or my commitment to work with you toward development of Badami, I will restate them for the record.

First, I think we can both agree that a determination of whether to voluntarily unitize state leases depends upon an affirmative finding that to do so is in the state's best interest. Also, you and I both know that there are statutory and regulatory standards which guide the department's evaluation of a proposal to unitize. Just saying that it is in the state's best interest does not make it so. Against that backdrop of common understanding, I began our discussion last week by saying that, as a technical matter, I did not believe the specific factual circumstances of the Badami Unit fit the conclusory affirmation of benefits which B.P. cited in its application.

For examples, we discussed certain of the criteria of 11 AAC 83.303. While B.P.'s application makes conclusory statements about how the state's interest with respect to these criteria is enhanced, I pointed out that the facts do not seem to support the statements. Since there is no diverse ownership interest, for example, I noted that it would be difficult to make a written finding that unitization prevents competitive capture of the resource, reduces duplication of activities or facilities or minimizes the overall footprint of development. B.P. makes these claims, but the facts suggest that unitization, as opposed to lease operations, will not provide greater benefits, given that, in fact, no diverse ownership interests exist.

Enclosure 14

We went through several similar examples of problematic areas where I explained that I simply did not see how I could make the affirmative best interest findings required by law. However, rather than rejecting the application out of hand, as your letter would seem to suggest I did, I asked you to review my specific concerns with B.P.'s attorneys, and to provide a written response to them. I thought you had agreed to provide that response. The comments in your letter that "...in the interim we will expand and clarify our arguments supporting formation of the Badami Unit..." seem to confirm that this is still your intent.

We also talked about B.P.'s proposed Five Year Unit Plan of Exploration and the requested amendment to the royalty terms of the leases which are proposed to be unitized. I want to address both of these issues separately because each deserves a detailed response so that you understand the basis of my concerns.

First, as to the Plan of Exploration. In my view, what B.P. has actually proposed is a plan of non-exploration. In your letter you claim that "...We believe that unitization of the Badami area is absolutely essential to moving the prospect closer to development, protect natural resources and the environment and serve the State's best interest." (emphasis mine). One of the fundamental questions facing both B.P. and the state at this juncture is "what is the Badami development area?" The significance of that question is really at the heart of any determination of how the state's interests would be affected by its agreement with the terms B.P. proposes in its application.

Specifically, two wells have been drilled to date—one each on two adjoining leases in the area proposed to be encompassed by the Badami Unit. Both of those wells, Badami 1 and Badami 2, have been certified as capable of producing in paying quantities by the department. Based upon the results of those wells, B.P. has identified a rather compact area in which to focus its efforts to determine whether the discovery can be commercially produced. While I would not disagree with you over whether this relatively small area constitutes the "Badami Development Area," the same thing cannot be said of the vastly larger area which B.P. proposes to unitize.

In addition to the two leases upon which the discovery wells were drilled, B.P. also proposes to unitize 10 adjoining leases encompassing almost 40,000 acres. More than half of those lease are scheduled to expire in either 1995 or 1996, and although each carried a primary term of ten years, they have yet to be explored. Unitization, under the terms you have proposed, would extend to B.P. a potentially very valuable property right in these leases for a minimum additional term of five years. Yet, B.P. is unwilling to make specific commitments to explore any of these leases during the Plan of Exploration period.

As I said during our meeting, I can fully understand B.P.'s desire to secure what essentially amounts to a five or more year option on the surrounding land without having to make a firm commitment to exploration or development of that area. What I cannot understand is B.P.'s inability to recognize that its interests and those of the state are not necessarily coincident. Your proposal requires the state

to extend to B.P. the benefits of a voluntary unit which does not provide for adequate and timely exploration and delineation of all of the unit acreage.

So, one of the points on which we obviously disagree is what constitutes an adequate exploration plan for the proposed unit. What B.P. has proposed—perhaps two wells sometime in a five year period—might be adequate if the unit area were confined to the leases which have been shown to be productive. The same plan, however, is inadequate for evaluating an area as vast as B.P. proposes to unitize.

We simply have a different view of prudent development. You characterize my reaction to B.P.'s proposed Plan of Exploration as indicative that, "...the DNR Director appears to be in the mode of discouraging prudent development...." I would suggest, alternatively, that it is my commitment to prudent development that really is the source of any disagreement. The plan you propose simply does not promote prudent development of the area proposed for unitization.

The proposed unit Plan of Exploration would, however, allow B.P. to pursue development of its core discovery area while giving it an option on other nearby lands without a concomitant obligation for their timely development. Again, I can appreciate the pressure you are under to present your management with an agreement that maximizes its options, reduces its costs and enhances its revenues. I believe that we can even agree that those goals can be harmonized with the state's interest under certain conditions. Where we disagree is in our respective views of whether the terms you have proposed achieve that end. I respectfully believe that they do not, but I remain open to discussing alternate proposals which would either reduce the unit area or expand the exploration plan to ensure prudent development of any unitized leases.

We also disagree on whether B.P.'s proposed amendment of the lease royalty provisions is either statutorily permissible in the context of unitization or, assuming for the sake of argument that it is, that it is in the state's best interest. While you characterize B.P.'s proposal as an "amendment" to the royalty terms under AS 38.05.180(p) which can be accomplished through unitization, it appears in every respect to be a royalty reduction, which I believe to be governed by the provisions of AS 38.05.180(j).

How do I get to the conclusion that the amendment constitutes a royalty reduction? The leases which B.P. proposes to unitize have a weighted average royalty of 14.7 percent. The royalty amendment B.P. proposes would substitute a sliding scale royalty with a minimum royalty of 5.0 percent and a maximum royalty of 20.0 percent. The actual royalty would be determined by the movement of a Reference Oil Price defined to be the average of the daily high and low Platts sales prices for ANS delivered on the West Coast for the month preceding the production month deflated to January, 1995 dollars.

To determine the effect of such an amendment, we applied the sliding scale formula retroactively from October 1990 through today. Its use during that period would have produced an average royalty rate

of 8.1 percent. The royalty rate would have exceeded the current weighted average royalty rate of 14.7 percent only once—and then for a short period—during the five month period coincident with the Iraqi invasion of Kuwait. Applying the formula prospectively from 1995 through 2016, using the Department of Revenue's Base Case Fall, 94 forecast, would produce an average royalty rate of 6.98 percent. Thus, based upon the past and our best estimate of the future, the formula is unlikely to yield royalty rates equivalent to the current rates.

To make matters worse from the state's perspective, B.P. proposes that the formula could never be reopened and that the Reference Oil Price be deflated monthly to January, 1995 dollars, thus taking away any "index creep" from which the state could otherwise benefit. Deflation of the royalty value, of course, begs the question of why, if the economics of the prospect work in nominal dollars (dollars-of-the-day), then shouldn't the state enjoy the benefits of inflation-affected nominal prices along with B.P.?

Aside from the fact that B.P.'s proposed royalty amendment appears to be a royalty reduction, it presents other concerns as well. First, its "need" is predicated upon the unconfirmed supposition that Badami development will not be profitable under the lease terms. However, B.P. has not yet confirmed the size of Badami—and thus at this juncture cannot know what its recoverable reserves may be. Without knowing either the reserves or their areal distribution, B.P. cannot reliably estimate its costs to develop them. And, of course, neither the state nor B.P. know what future oil prices will be. Under these circumstances, neither of us are able to determine what B.P.'s revenues will be, much less what its profits may be.

Under these circumstances, B.P.'s proposal asks the state to assume a greater share of the risks. It is obvious that the economics of any prospect from the lessee's perspective will be enhanced if the state's royalty share of production is reduced. The questions of when it is appropriate to do so and how much quantitative support is necessary to find that it is in the state's best interest remain, however. The questions loom even larger when, as here, the amended royalty formula would be insensitive to the field's profitability, would not be subject to reopeners and would be artificially deflated so as to continually raise the hurdle for increased royalty rates.

Again, I can appreciate your desire to minimize risk, enhance profitability and preserve options. However, there seems to be a fundamental imbalance in this instance where the state is being asked to adopt a royalty scheme that is both insensitive to B.P.'s profits, and which will likely, under most conceivable circumstances, result in substantial royalty reductions.

Finally, I must disagree with your characterization of our meeting last week as offering no encouragement. I pledged then, and I reaffirm now, my willingness to work with you directly to see if we can find common ground that makes sense for both parties within the framework of the statutes and the regulations. To that end, my staff and I met more than six hours this past Wednesday to develop an alternative exploration plan that we believe would assure timely evaluation of the unit area. That effort was undertaken in anticipation that the discussions between B.P. and the division

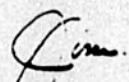
Mr. T. J. Obeney

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December 9, 1994

would continue. Meanwhile, we will publish notice of B.P.'s unit application this Sunday, triggering the 60 day public comment period. I suggest that the way forward begin with scheduling a meeting at your earliest convenience so that we can continue our discussion.

Sincerely,


James E. Eason
Director

ENCLOSURE 15



BP EXPLORATION
Alaska Exploration & Development Department

BP Exploration (Alaska) Inc.
900 East Benson Boulevard
PO Box 190072
Anchorage, Alaska 99519-8872
907 561 5111

January 16, 1995

State of Alaska
Department of Natural Resources
Division of Oil and Gas
3601 C Street, 13th Floor
Anchorage, AK 99503

Attn: Mr. James E. Eason, Director

Subject: Meeting January 9, 1995
Decision Criteria and Considerations
Badami Unit Application
North Slope, Alaska

Dear Mr. Eason:

Further to our meeting of January 9 and in order to address some of the concerns mentioned in your letter of December 9, 1994, we hereby submit the following in support of the Badami Unit application:

We are disappointed in your current lack of support for our sliding scale royalty proposal and are concerned about your onerous Plan of Exploration (POE) proposal. However, we believe the single most important issue, at this time, is whether the unitization of the Badami area is justifiable. Until the validity of unitization is resolved, there seems little point in discussing the Royalty or POE issues.

Therefore with the directions we received at our last meeting, we submit the following in support of unitization of the Badami area:

No Loss To The State

While, in theory, the State could construct an argument that Unitization may not enhance the State's interest, we would argue that approval of the Badami Unit would not harm the State's interest and under all reasonable scenarios would be in the State's best interest. Unitization of this area would improve the likelihood of development and accelerate the start of production. With the limited life span of

Letter - Mr. Eason
Re: Badami Unitization
January 16, 1995
Page 2 of 3

the North Slope infrastructure and TAPS, an earlier startup date would likely lead to increased recovery of reserves.

Permitting Complications And Increased Administrative Burden

Permit applications and development schedules for the Badami area have been prepared based on the assumption that the leases have been unitized. As such, a Lease Operation Permit is ready for submittal. The turn-around time for such a permit is only a few months which means it would be issued in plenty of time to enable BP to sanction the project in time for a 1997 startup. In the absence of a Unit, Tidelands permits would be required for each lease. Such permitting would be an additional administrative burden to the State and BP and would likely take a year or so to acquire such permits. This would delay sanction and production startup, as stated above. project delay could lead to loss reserves.

Increased Administration Costs And Reserve Loss By Lease Operations

Absent Unitization, under individual lease operations, there would be no Participating Area and no Tract Participating Factors. In the absence of the latter, production must be separately measured by lease for the payment of royalty. Separate measurement requires multiple separation and metering trains, one for each lease instead of a single integrated train. There would be substantial costs and economic loss under such a scenario. Indeed, the higher costs would most certainly make the project, which is already marginal, uneconomic and undevelopable. Operating costs would also be higher leading to an earlier abandonment and reserve loss. Increased facilities would also be required resulting in an enlarged development footprint and environmental impact. Increased facilities require greater manpower to operate and maintain which would increase aviation, road traffic and camp requirements. Each of these carries an incremental environmental effect. Even in the instance where the State agrees to allow production measurement by allocation, based test data, there are increased administrative costs by BP and the State as well as increased capital costs for testing facilities and increased operating costs for operations. Any operating cost increase carries an associated reserve loss:

Each of these items leads to the inevitable conclusion that Unitization of Badami is in the best interests of both the State and BP.

Finally, we would like to express our concern over the State's position that the lack of diverse ownership at Badami weakens the justification for formation of a Unit. As you know we have been working with our partner, Petrofina, to eliminate or reduce potential future conflicts by attempting to align our interests in the leases in and around the first two Badami wells. Now it appears that this

Letter - Mr. Eason
Re: Badami Unitization
January 16, 1995
Page 3 of 3

desirable activity has created a "catch-22" situation. An activity aimed at enhancing the likelihood of development is interpreted by the State as a reason to argue against the necessity of forming a Unit. The absence of a Unit at Badami can only introduce uncertainties which lead to the potential for conflict and delay in development. This will result in economic loss to all the parties. Further, if the current alignment between the owners decays because of the absence of a Unit, or leases change hands because of lease expiration, we will find ourselves faced with the potential for competitive developments. This, in-turn, will require the formation of a Unit. It is reasonable therefore to conclude that all likely paths ultimately lead to the formation of a Unit, as is the case with all producing fields on the North Slope. The State would appear to gain nothing, and risk significant economic loss, by denying Unitization at Badami.

I hope these arguments encourage you to re-visit your recent letter and we can conclude the Unitization issue and move on to the other issues. If you have any questions, please call me at (907) 564-5989.

Yours sincerely,



T.J. Oberney
Manager, New Developments, Alaska

ENCLOSURE 16

TONY KNOWLES, GOVERNOR

DEPT. OF NATURAL RESOURCES

DIVISION OF OIL AND GAS

PO BOX 107334
ANCHORAGE, ALASKA 99510-7334
PHONE: (907) 782-2553

January 20, 1995

Via Fax (564-5200) and U. S. Mail

Mr. T. J. Obeney
Manager, New Developments, Alaska
BP Exploration (Alaska) Inc.
900 East Benson Boulevard
P.O. Box 196612
Anchorage, Alaska 99512-6612

Dear Mr. Obeney:

I am responding to your January 16, 1995 letter regarding our January 9, 1995 meeting to discuss BP's Badami Unit Application (application). Given that more than five weeks have passed since my December 9, 1994 letter to you identifying the application's deficiencies, the substance of your recent letter surprised me. My stated concerns regarding the substance of BP's Plan of Exploration (POE) and its proposed sliding scale royalty amendment have yet to be addressed. In fact, reading your most recent letter "cold," one would be hard pressed to imagine that I had ever written my December 9, 1994 letter, much less that we had a subsequent meeting on January 9, 1995, in which I had laid out a virtual road map, with specific alternatives, for BP's approaching unitization of the Badami prospect.

We spent more than two hours during our January 9 meeting discussing specific language and issues which I believe would cure the "justification of unitization" issues, i.e., making the facts of BP's proposal conformable with the criteria of 11 AAC 83.303. However, your letter appears simply to disregard what I had hoped were to be constructive results of that discussion. Instead of acknowledging any progress on that front, you note "...we believe the single most important issue, at this time, is whether the unitization of the Badami area is justifiable. Until the validity of unitization is resolved, there seems little point in discussing the Royalty or POE issues." (emphasis added.)

Also in our January 9th meeting, I provided BP a specific, written alternative POE, as I had promised in my December 9, 1994 letter to you. We spent a considerable amount of time explaining the basis for the proposed alternative and answering several questions which you raised. We concluded our meeting with a discussion of the basis for my belief that the division lacks the authority to amend the lease royalty terms by substituting a sliding scale royalty such as BP has proposed. As I noted in my December 9th letter, the amended application appears in every respect to be a royalty reduction which can only be accomplished through the procedures set forth in AS 38.05.180(j).

Thus, when we met on January 9th, the issues separating us were how to address (harmonize) the language of BP's application with the statutory and regulatory criteria governing unitization, how to define an appropriate POE, given the "area" BP proposes to include in the unit, and how to address BP's proposed "amendment" to the lease royalty provisions. As to the first issue, I believe we both now understand how to come to closure. As for

January 19, 1995

the two remaining substantive issues, what is an appropriate POE and whether lease royalty terms can be amended as BP has proposed, they remain unresolved.

The division has proposed changes to BP's application that will make the proposed unit technically and legally defensible, and fair to all parties. We have described in writing specific concerns about those areas where we believe the Badami Unit application to be deficient; we have provided suggested remedies. We have offered an alternative POE that would assure timely and thorough exploration of all the Badami area, not just the Badami discovery area. We have also taken the further step in our meeting on January 9, 1995 of inviting you to propose an alternative POE, i.e., a less ambitious program than our alternative, but for a smaller unit area, if you desire. BP's sole response, as conveyed in your most recent letter, seems to be "...We are disappointed in your current lack of support for our sliding scale royalty proposal and are concerned about your onerous Plan of Exploration (POE)."

I believe the state and BP can find a common interest in unitization of the Badami discovery, but only with a POE appropriate to the area proposed, and only under the leases' current royalty provisions, absent changes in the law. On this last point, you appear to be unwilling to revise your application to withdraw BP's proposed royalty amendment. In our last meeting, you even asked whether someone else sitting in my seat would make the same decision, inferring that the law may be subject to multiple interpretations. As I told you then, I still believe that it is unlikely that BP can persuade anyone else to overlook the consistent written policy of the past three administrations and the legal advice which supported that policy. However, you should make an independent judgment of the likelihood of your success in that regard. To assist you in understanding the issue from our perspective I have enclosed a number of documents for your review. These include letters by former commissioners Wunnicke and Brady, as well as former Division of Oil and Gas Director Brown, which address the department's royalty reduction authority.

In closing, I urge you to focus on the remaining issues which need to be resolved if unitization of Badami is to occur. BP's approach to date seems to be unitization under its proposed terms - or not at all. I continue to believe there are legal and technical issues which will prevent us from ever closing under those terms. However, I remain open to continuing discussions which are responsive to the concerns I have raised. Neither of us should forget, however, that the clock is ticking. The public comment period has closed, and under the provisions of 11 AAC 83.316, a written decision approving or denying BP's application must be issued no later than March 14, 1995.

Sincerely,


James E. Eason
Director

Enclosures

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STATE OF ALASKA

DEPARTMENT OF NATURAL RESOURCES

OFFICE OF THE COMMISSIONER

BILL SHEFFIELD, GOVERNOR

FOUCH M
JUNEAU, ALASKA 99811
PHONE: 937-465-2400

March 17, 1986

The Honorable Arliss Sturgulewski
Chair, Senate Resources Committee
P.O. Box V
Juneau, AK 99811

Dear Senator Sturgulewski:

The Department of Natural Resources supports SB 410, which is scheduled for a hearing today in the Senate Resources Committee. The bill would authorize the commissioner of the Department of Natural Resources under certain circumstances to reduce or revoke oil or gas royalty obligation increases made in connection with the institution or operation of a cooperative or unit plan.

The bill primarily would affect the Milne Point Unit, a small North Slope oil field which began production last fall.

Conoco, Inc., the Milne Point Unit operator, has been seeking for several years to roll back a 20% royalty on certain Milne Point leases. The royalty obligation on those leases was increased from 12.5% to 20% under an agreement required by the department in 1979 as a condition of approval of the Milne Point Unit.

As a result of an application for royalty relief filed last fall by Conoco and Milne Point Unit working interest owners Reading and Bates Petroleum Company, Champlin Petroleum Company and Cities Oil and Gas Corporation, the department has examined confidential economic, geological, geophysical and engineering data supplied by the companies. Based upon that review, the department believes that rescinding the royalty increase would encourage continued production and further development of oil reservoirs within the Milne Point Unit.

Under existing and forecasted economic conditions, there is a high likelihood that both the economic and physical recovery of oil and gas at Milne Point will not be maximized for either the companies or the state at a royalty rate of 20%. Production of oil and gas from the developed reservoir (i.e., the Kuparuk River formation) will not be maximized, and development and production of oil and gas from yet to be

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March 17, 1986

developed reservoirs (i.e., the Shallow Sands - heavy oil and gas reservoirs, geologically equivalent to ARCO's West Sak-Ugnu reservoirs at Kuparuk Unit) likely will not occur at all. The companies have made a persuasive case that they cannot be reasonably assured an adequate rate of return on any future or incremental investment under the existing 20% royalty. Given the further erosion of crude oil prices since the application was filed with the state last October, it is possible that current production will be halted if the royalty rate on the leases remains at 20 percent.

A careful review by staff of the data and analyses supplied by the companies confirms that, under current and expected market conditions, the companies likely will not receive an adequate rate of return on their current investments, and that future investments in the Milne Point Unit also would yield a less than satisfactory return. It is also very likely that if current conditions persist (or get worse), the field will be shut-in if the royalty remains at 20%. In addition, future development of the Milne Point Unit Shallow Sands is almost certain not to occur at a 20% royalty.

A reduction in the royalty rate from 20% to 12.5% would result in a revenue decrease to the State of approximately \$4.5 million a year from the Milne Point Unit. (See attached fiscal note.)

The department has tried to address the need for royalty relief within the current statutory framework, and earlier this year proposed that the royalty obligation be changed (not reduced) to a 12.5% royalty and a 3% Net Profit Share in lieu of the current 20% royalty. The companies have not accepted this proposal, even though it would have the effect of an immediate reduction in the royalty obligation, and would leave open the opportunity for the companies to apply for further relief after two years of field production based on the facts and circumstances at that time.

The department has been constrained from considering an outright royalty reduction by AS 38.05.180(j), which precludes the commissioner from granting a reduction of a lease 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 that field."

The department's proposal to change the existing royalty rate was based on the authority of AS 38.05.180(p), which authorizes the commissioner to change royalty requirements of unitized leases "as the commissioner determines necessary

March 17, 1986

or proper to secure the proper protection of the public interest." Under the department's proposal, the state likely would have been compensated for the near-term revenue losses resulting from a reduction to a 12.5% royalty rate by the further receipt of revenues from the development of the Shallow Sands reservoirs at Milne Point and the application of the 15% Net Profit Share and the 12.5% royalty to that production. Revenues to the state over time likely would have been equivalent or greater under the department's proposal, but the income would have been delayed.

The department believes that it is not authorized to reduce the royalty obligation under AS 33.05.130(p), because of the limitation AS 33.05.130(j) appears to place on the commissioner's powers. If AS 33.05.130(j) applied only to leases that had not yet been unitized, AS 33.05.130(j) would be a nullity because, as a practical matter, unitization always precedes production. Related statutes should not be construed to make one statute a nullity.

Further, the general rule of statutory construction is that specific provisions control general provisions. Under this rule, the specific royalty reduction provisions of AS 33.05.130(j) would control the general provisions of AS 33.05.130(p).

Further, the legislative history of AS 33.05.130(j) argues against using AS 33.05.130(p) to circumvent the royalty reduction limitations stated in AS 33.05.130(j).

Testimony before the Legislature in 1978 focused on royalty reductions in conjunction with the increased flexibility given to the commissioner to select bidding methods. A prime concern was to prevent royalty bid manipulation, where a bidder obtains a tract by bidding an unreasonably high royalty counting on a subsequent royalty reduction to make the lease profitable. Although the companies obtained their leases at a fixed royalty sale, the policy against royalty bidding is arguably still applicable. The companies' leases were about to expire, causing the companies to agree to increase royalties in order to keep from losing the leases which were about to expire.

The bill that created AS 33.05.130(j) went through several committee substitutes. One committee, the House Resources Committee, voted to place an express limit on the commissioner's powers under AS 33.05.130(p) by adding the language: "however, the commissioner may not reduce the state's royalty within any unit except as provided in (j) of this section." A subsequent committee reviewing the bill, the Senate Resources Committee, deleted that language, but its sole motive was that the language was unnecessary since that committee had already decided to delete AS 33.05.130(j) altogether.

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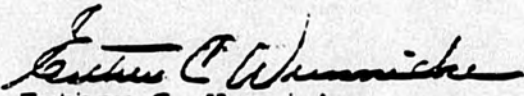
March 17, 1986

Later in the Senate Resources hearing, DNR pointed out that AS 33.05.130(j) granted the commissioner less power to reduce royalties than existed at that time under AS 33.05.140. The committee then voted to amend AS 33.05.140 to delete the commissioner's royalty reduction powers for oil and gas, and voted to reinstate AS 33.05.130(j). The committee immediately adjourned, without taking up the question of whether the previous committee's limitation of AS 33.05.130(p) should be retained.

In view of this legislative history, the department concluded that the specific royalty reduction limitations stated in AS 33.05.130(j) control the general royalty reduction powers granted in AS 33.05.130(p).

Thank you for the opportunity to comment on SS 33-130.

Sincerely,


Esther C. Wunnicks
Commissioner

Attachment:

cc: Senator Settya Fahrenkamp

BILL SHEFFIELD, GOVERNOR

DEPARTMENT OF NATURAL RESOURCES

DIVISION OF OIL AND GAS

POUCH 7034
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.

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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 belabored 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.

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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 Kekikuk 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 of 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 Social 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

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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

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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 of 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 LeRasche 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.

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

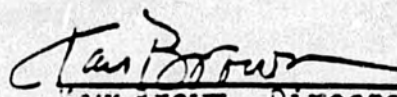
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H. D. Haley
Conoco, Inc.

October 9, 1984
Page 8

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.


Ray Brown, Director
Division of Oil and Gas

Enclosures

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AGG 1187129

STATE OF ALASKA

DEPARTMENT OF NATURAL RESOURCES

OFFICE OF THE COMMISSIONER

STEVE COWPER, GOVERNOR

400 WILLOUGHBY AVE
JUNEAU, ALASKA 99801-1774
PHONE: (907) 465-2400

April 29, 1987

Mr. Tom Painter
Division Manager
Conoco, Inc.
3201 C Street
Suite 200
Anchorage, AK 99503

Dear Mr. Painter:

As you requested in your April 20, 1987 letter, I am writing to inform you of my decision regarding whether the department has the statutory authority to grant Conoco a reduction in its royalty on production from the Milne Point Unit in November, 1987.

My staff and I have reviewed both the applicable statutes and the history of production at the Milne Point field carefully. In addition, we have conferred with Assistant Attorney General Steve Porter who has conducted a review of the legislative history, the statutes and the case law on our behalf. Based upon that review, I have concluded that I do not have the authority to approve a request to reduce royalty rates until after two years of production from the Milne Point Unit has occurred.

Although November, 1987 represents the two-year anniversary of the commencement of production from the Milne Point Unit, two years of initial production will not have occurred by that time. My reading of the statutes confirms that there must be two years of actual production to form the basis for the economic review which must precede and support any decision to reduce the royalty rate for a producing field. Thus, the two-year period of initial production for the Milne Point Unit is tolled during the period production is suspended, as is currently the case.

Staff from the Division of Oil and Gas concur with Conoco's economic assessment of the losses incurred by continued production at Milne Point, and agree that had those losses been experienced over a two-year production history, a royalty reduction would be advisable. On the basis of their

ANCHORAGE DIVISION	
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Mr. Tom Painter

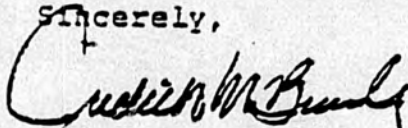
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April 29, 1987

analysis I remain sympathetic to Conoco's dilemma. However, the department's options are limited under the statutes, and a royalty reduction at this time is not possible.

If you have any additional questions or are interested in discussing other options which might be available, please feel free to call me.

Sincerely,



Judith M. Brady
Commissioner

ENCLOSURE 17

SUMMARY OF LEASE SALES THAT OFFERED EXPLORATION INCENTIVE CREDITS

SALE #	SALE AREA	TRACT #S	ADL NUMBERS	RATE PER FOOT DRILLED	% CAP ON COSTS	EIC TERM	EFFECTIVE DATE OF LEASES	# OF ACTIVE LEASES 1/23/95	# TRACTS OFFERED W/EICs	EICs GRANTED
36	BEAUFORT SEA	001-012	343101-343112	\$750	40%	10 YEARS	8/1/82	4	12	1
37	MIDDLE TANANA BASIN	005-154	345005-345154	\$250	30%	7 YEARS	11/1/82	0	150	1
34	PRUDHOE BAY UPLANDS	001-014	344003-344017	\$500	40%	10 YEARS	12/1/82	0	15	1
		015-261	344018-344245	\$375	30%	10 YEARS	12/1/82	0	228	2
39	BEAUFORT SEA	001-017	355001-355017	\$1,600	40%	10 YEARS	8/1/83	3	17	2
		018-041 & 047	355018-355041 & 355047	\$1,200	30%	10 YEARS	8/1/83	23	25	5
43A	COLVILLE RIVER DELTA	070-078	364470-364478	\$1,200	30%	10 YEARS	8/1/84	9	9	1
	PRUDHOE BAY UPLANDS	079-084	364479-364484	\$375	30%	10 YEARS	8/1/84	0	6	0
54	KUPARUK UPLANDS	001-089	372001-372108	\$300	15%	5 YEARS	4/1/88	47	108	2
70A	KUPARUK UPLANDS	001-135	375001-375135	\$300	20%	5 YEARS	4/1/91	101	135	5
								187	705	20

The State offered Exploration Incentive Credits in seven competitive lease sales from 1982 through 1991. EICs were offered on 705 tracts. Only 20 wells have been drilled earning EICs. The State has granted EICs totaling \$58,666,846.26.

Enclosure 17

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ENCLOSURE 18

ARCO Alaska, Inc.
Post Office Box 100360
Anchorage, Alaska 99510-0360
Telephone 907 265 6101

James M. Davis
Senior Vice President

NOV 12 AM 11:15



RECEIVED

NOV 15 1993

November 9, 1993

DIVISION OF OIL & GAS

State of Alaska
Department of Natural Resources
Division of Oil and Gas
P.O. Box 7034
Anchorage, AK 99510-7034

HAND DELIVER

Attn: Mr. James E. Eason, Director

Gentlemen:

ARCO Alaska, Inc., on behalf of itself and Union Texas Petroleum Alaska Corporation, is hereby filing the attached Application For Exploration Incentive Credits for expenditures through October of 1993 in conjunction with drilling the Kuukpik Unit #3 on ADL-364477. This Application is made pursuant to 11 AAC 83.800 and the Notice of State of Alaska Competitive Oil and Gas Lease Sale 43A.

The Kuukpik Unit #3 well spudded on February 16, 1993 and was drilled to a measured depth of 6,880' feet. Total depth was reached on March 3, 1993 and the well was abandoned on April 14, 1993. Based upon the Exploration Incentive Credit guidelines contained in the Notice of Sale, the gross credit is \$2,794,016.15, being 30% of the total well costs to date of \$9,313,387.16.

The Notice of State of Alaska Competitive Oil and Gas Lease Sale 43A requires that the EIC must be earned and used within ten (10) years of the effective date of the lease. This will require that the EIC must be used prior to August 1, 1994. We will appreciate the State's consideration in this regard.

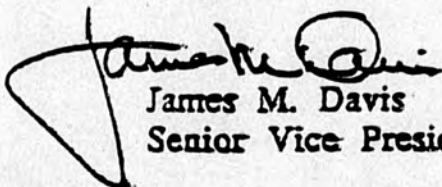
Enclosure 18

State of Alaska
Exploration Incentive Credits Application
November 9, 1993
Page 2

In accordance with 11 AAC 83.815, the attached Application for Exploration Incentive Credits is being submitted in triplicate. Please note that this is not a final accounting for Kuukpik Unit #3. Once a final accounting is available, we will file an additional application for any remaining credits. Should you have any questions or require additional information, please contact Brad Dowdell at 265-6115.

We appreciate your consideration in this matter.

Very truly yours,


James M. Davis
Senior Vice President

IT

Attachment

cc: Elizabeth Williams
Union Texas Petroleum Alaska Corporation
1330 Post Oak Road
Houston, TX 77056

ENCLOSURE 19

The original Kuukpik #3 EIC Decision and Finding contains information that is confidential under AS 38.05.035 and 11 AAC 82.810. The enclosed copy of the Decision and Findings contains only those sections of the document that do not incorporate or discuss confidential data. DNR Commissioner Noah found that the Kuukpik #3 well failed to qualify as an "exploration well" as defined by 11 AAC 02.020 and therefore was not eligible for an EIC.

WALTER J. HICKEL, GOVERNOR

DEPARTMENT OF NATURAL RESOURCES

OFFICE OF THE COMMISSIONER

P.O. BOX 107005
ANCHORAGE, ALASKA 99510-7005
PHONE: (907) 762-2483

CERTIFIED MAIL # P 377 614 920
Return Receipt Requested

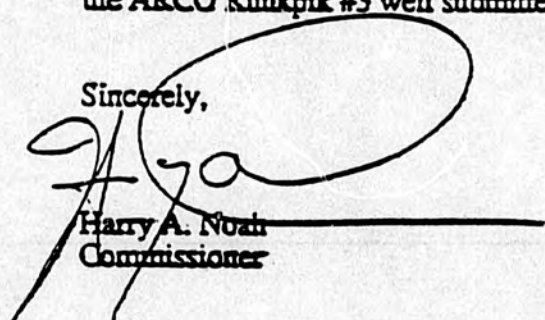
October 13, 1994

Mark R. Landr, District Landman
ARCO Alaska Inc.
P.O. Box 100360
Anchorage, Alaska 99510-0360

Dear Mr. Landr:

Enclosed is my decision regarding the application for an exploration incentive credit for the ARCO Kuukpik #3 well submitted by ARCO and Union Texas Petroleum.

Sincerely,



Harry A. Noah
Commissioner

Enclosure

7

Confidential

**ALL CONFIDENTIAL INFORMATION HAS BEEN DELETED
FROM THIS COPY OF THE DECISION AND FINDINGS**

**DECISION AND FINDINGS OF THE COMMISSIONER
ALASKA DEPARTMENT OF NATURAL RESOURCES ON THE APPLICATION
FOR EXPLORATION INCENTIVE CREDITS FOR THE ARCO KUUKPIK #3
WELL**

I. INTRODUCTION AND BACKGROUND

ARCO Alaska Inc. (ARCO), on behalf of itself and Union Texas Petroleum, applied for an exploration incentive credit (EIC) for the ARCO Kuukpik #3 well (Kuukpik #3). The application claimed total well costs of \$8,256,000.00 and requested a credit of \$2,794,016.15. The application is denied because the Kuukpik #3 fails to qualify as an "exploratory well" under the EIC regulations.

The Kuukpik #3 was drilled on ADL 364477. This lease was offered in Competitive Oil and Gas Lease Sale 43A which was held May 22, 1984. ADL 364477 was eligible for an EIC to be calculated at the rate of \$1200 per foot drilled for the first exploratory well per tract (lease). The credits, however, could not exceed 30 percent of the total exploratory well costs. The credits were to be earned and used within 10 years of the effective date of the lease. The Kuukpik #3 was spudded on February 16, 1993, drilled to a measured depth of 6880 feet and abandoned on April 14, 1993.

ARCO submitted the application on November 9, 1993. The Division of Oil and Gas (Division) requested additional technical data from ARCO. These data requests resulted in several meetings and numerous phone conversations between Division and ARCO staff and the transmittal of confidential well, seismic, engineering data and other information. Several times the Division specifically requested ARCO's pre-drill prospect maps. Nevertheless, ARCO did not provide them. The application was considered complete and following notification of ARCO, the record was closed on June 10, 1994.

On July 27, 1994 the commissioner supplied ARCO with a draft decision denying the EIC and allowing ARCO until August 15, 1994 to submit any comments or additional materials that they wished to be considered before a final decision was issued. Following their receipt of the draft decision ARCO requested and received a meeting with the Division to discuss the draft decision. At that July 28, 1994 meeting, Division staff explained the draft decision, discussed EIC regulations and restated the need for ARCO to supply a pre-drill prospect map (preferably a net pay isopach map). On August 15, 1994 ARCO requested a two-week extension of the August 15 deadline in order to gather additional data and comment on the draft decision. This request was granted by DNR. ARCO submitted their additional information to the Division on August 29, 1994. A discussion of their data and interpretations appears in Section III.

II. DISCUSSION OF THE EXPLORATION INCENTIVE CREDIT DECISION CRITERIA

Under AS 38.05.180(i), the commissioner of the Department of Natural Resources was authorized to establish an EIC system to encourage exploration of state leases through either geophysical work or the drilling of an exploratory well. An EIC is an optional provision in the state's lease form and is designed to encourage early exploration of its lands for hydrocarbon potential.

Under 11 AAC 83.800, the commissioner might or might not grant an EIC for costs incurred in either drilling an "exploratory well" or conducting "geophysical work". Under 11 AAC 83.820, "exploratory well" is defined as:

a well drilled for the purpose of oil and gas exploration that

(A) is located three miles or more from any other well drilled for oil and gas with all distances measured as the horizontal distance between exploration targets, or

(B) is within three miles from a well drilled for oil and gas, but tests potential hydrocarbon traps that the commissioner, after analyzing evidence submitted by the lessee and other information, determines constitute a distinctly separate exploration target.

To qualify as an "exploratory well" the commissioner, first must find that the well was drilled for the "purpose of oil and gas exploration". Second, he must find that either one of the two criterion has been established: (1) the distance criterion (A) above, or (2) the separateness criterion (B) above. For purposes of this discussion, it is assumed that the Kuukpik #3 was drilled for the purpose of oil and gas exploration.

(A) The distance criterion. The distance criterion provides an objective, measurable test to determine if a well qualifies as an exploratory well. To qualify for an EIC under this criterion, an oil and gas well must be drilled three miles or more from another oil and gas. The distance between wells is the horizontal distance between the well penetration of the target in the applicant's well and the well penetrations of the targets of surrounding wells. This is a critical aspect of the EIC regulations and the lessee should ensure that the well bore is three miles or more from other wells in order to qualify for the credit under the distance criterion.

(B) The separateness criterion. If a well does not meet the distance criterion, it may still be considered an "exploratory well" under the EIC regulations if the well meets the separateness criterion. Under the separateness criterion, the well must target "potential hydrocarbon traps" that the commissioner determines to be a "distinctly separate exploration target" from any other known oil and gas traps or accumulations. "Target" implies the primary geological trap or accumulation identified by the operator before drilling the well (See H. William & C. Meyers, Oil and Gas Terms 984 (7th ed. 1987)). The target must be "distinctly separate." This suggests that the targeted trap must be "set apart from ... [,] not connected [with, or] disjoined from any other trap (The American Heritage Dictionary of the English Language, 1181 (1970)). Moreover, the applicant bears the burden to show that this separateness is distinct.

III. APPLICATION OF THE DECISION CRITERIA

The Kuukpik #3 was drilled less than three miles from two previously drilled wells, the Amerada Hess Colville Delta 25-13-6 #1 (A-H 25-13-6) and the Gulf Colville Delta (Gulf C-D). Therefore, since the well does not meet the distance criterion, in order to qualify for an EIC the well must satisfy the separateness criterion.

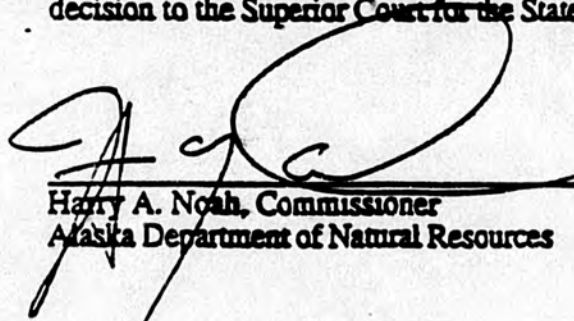
After examination of the data, ARCO's stated pre-drilling intent for drilling the well, and in light of the language and intent of 11 AAC 83.820, the Kuukpik #3 fails to qualify for an EIC. 11 AAC 83.820 requires that an "exploration well" which was drilled less than three

miles from another well, "tests potential hydrocarbon traps" that "constitute a distinctly separate exploration target". The word "potential" means "possible" as opposed to "actual" (Random House College Dictionary (1980)). This language insures that an EIC is awarded for drilling a specific, and "distinctly separate exploration target," that has been identified before drilling. EICs are not intended as reward for unexpected chance discoveries, delineation, or development wells. Additionally, use of the word "potential" allows DNR to grant an EIC regardless of what the well actually found, and thus, an EIC reward is not conditioned on a post-drilling analysis of the well results. This standard helps protect an applicant's right to an EIC if the well fails to discover a hydrocarbon trap.

IV. FINDINGS AND DECISION

The Kuukpik #3 was drilled less than three miles from the previously drilled A-H 25-13-6 and the Gulf C-D wells. Furthermore, the Kuukpik #3 failed to test potential hydrocarbon traps that constitute a distinctly separate exploration target from those found within the A-H 25-13-6 well. Therefore, the Kuukpik #3 fails to qualify as an "exploratory well" under 11 AAC 83.820 and does not qualify for an EIC. ARCO's application is denied.

Absent the filing of a request for reconsideration with the Commissioner in accordance with 11 AAC 02.020, this decision constitutes the final administrative agency decision and, pursuant to Rule 602(a)(2) of the Alaska Rules of Appellate Procedure, you have thirty days from the date this decision is mailed or otherwise distributed to you to appeal the decision to the Superior Court for the State of Alaska.


Harry A. Noah, Commissioner
Alaska Department of Natural Resources

10/14/94
Date

ENCLOSURE 20

EXPLORATION INCENTIVE CREDITS

Report Month: November 1994

ADL	WELL	COMPANY	CERTIFICATION DATE	TOTAL AMOUNT
343109	G-2 Well	Exxon	10/05/83	\$6,197,625.00
		Standard Alaska	12/27/83	4,152,408.75
		BPAE	10/05/83	2,045,216.25
344010	Leffingwell	ARCO	10/02/84	3,706,000.00
		Union	10/02/84	3,706,000.00
344033	J-1 Well	Exxon	10/31/84	5,119,500.00
355005	Long Island Well	Exxon	11/14/84	1,367,738.00
		Standard Alaska	11/14/84	1,378,076.00
345130	Tonek Hills	ARCO Alaska	08/02/85	715,530.81
355037	Colville Delta #1	Texaco	07/09/86	637,500.00
		Amerada Hess	07/08/86	888,594.00
		Diamond Shamrock (A)	07/08/86	100,128.00
		Mobil	02/05/87	432,511.00
		Placid Oil (C)	07/08/86	314,679.00
		Union Texas (B)	07/08/86	475,631.00
		Rosewood Resources	07/08/86	12,662.00
		Hunt Pet Co.	07/08/86	11,213.00
364478	Colville Delta Area AHC 25-13-6 #1 Well	Amerada Hess	10/12/87	677,853.00
		Union Texas (G)	10/12/87	508,390.00
		Texaco	10/12/87	225,951.00
		Maxus Expt. (G)	10/12/87	225,951.00
		Placid Oil	10/12/87	129,115.00
		Rosewood Res.	10/12/87	21,360.00
		Hunt Pet Co. (G)	10/12/87	18,987.00
355038	Colville Delta #2	Amerada Hess	10/28/87	757,731.46
		Union Texas (G)	10/28/87	205,106.95
		Texaco	10/28/87	273,475.93
		Maxus Expt. (F)	10/28/87	273,475.93
		Placid Oil (H)	10/28/87	423,982.26
		Rosewood Res. (D)	10/28/87	77,561.49
		Hut Pet Co. (G)	10/28/87	68,943.50
355039	Colville Delta #3	Amerada Hess	10/28/87	364,048.13
		Union Texas (G)	10/28/87	91,012.03
		Texaco	10/28/87	364,048.13
		Maxus Expt. (G)	10/28/87	364,048.13
		Placid Oil (H)	10/28/87	178,918.37
		Rosewood Res. (D)	10/28/87	34,416.31
		Hut Pet Co. (G)	10/28/87	30,592.28
344176	Gyr #1	ARCO Alaska, Inc.	11/15/90	719,560.56
		Conoco	11/15/90	761,481.20
		Amerada Hess	11/15/90	761,481.20
		ARCO Alaska, Inc.	2/4/92	16,151.00
		Amerada Hess	2/4/92	9,479.94
		Conoco	2/4/92	9,479.93
355021	NW Milne #1	Conoco	7/10/92	1,440,243.90
		Conoco	2/9/93	660,321.00
		Conoco	6/16/93	24,764.70
375044	Sequoia #1	Conoco	7/10/92	288,641.79
		Petrofina	7/10/92	352,784.41
		Conoco	2/9/93	16,333.56
		Petrofina	2/9/93	19,963.24
375076	Cirque #2	ARCO Alaska, Inc.	2/9/93	884,118.53
375108	Tara #1	ARCO Alaska, Inc.	2/9/93	740,305.91
355036	Kalubik #1	ARCO Alaska, Inc.	2/9/93	3,019,927.70
		Union Texas	2/9/93	262,602.41
372104	Fiord #1	Union Texas Petro AK	2/9/93	191,018.62
		ARCO Alaska, Inc.	2/9/93	1,719,167.60
372006	Tulaga #1	ARCO Alaska, Inc.	3/25/93	1,635,000.00

355011	Jones Island #1	ARCO Alaska Inc. Union Texas	7/12/93 7/12/93	2,160,000.00 2,160,000.00
375133	Cascade Well #1	BP Exploration	4/4/94	925,348.63
375061	Yukon Gold #1	BP Exploration	8/8/94	3,312,689.72
GRAND TOTAL				\$58,666,846.26

- (A) Assigned \$432,511 of EIC to Mobil Oil Corp. effective 02/05/87
- (B) Assigned entire EIC to BP Alaska effective 02/03/87
- (C) Assigned entire EIC to Texaco Inc. effective 03/31/87
- (D) Assigned entire EIC to Texaco Producing Inc. effective 01/01/88
- (E) Assigned \$79,193.59 of EIC to Texaco Producing Inc. effective 02/01/88
- (F) Assigned entire EIC to Texaco Producing Inc. effective 02/01/88
- (G) Assigned entire EIC to Texaco Producing Inc. effective 05/17/88
- (H) Assigned entire EIC to Standard Alaska effective 05/17/88

Source: Alaska Department of Natural Resources, Division of Oil and Gas

ENCLOSURE 21

Incentive Credit For Geophysical Work

- To date, no company has applied for credit for conducting a geophysical survey.
- 11 AAC 83.310. Credit for Geophysical Work.
 - Copies of geophysical data obtained during a credit period must be submitted to the commissioner within 90 days after completion of collection and processing of data.
 - Geophysical work must be performed during the two seasons before the scheduled sale date.
 - Geophysical information which accompanies an application for EICs will be made public 30 days after the lease sale date. (this is why companies haven't taken advantage of this incentive.)

ARTICLE 8. EXPLORATION INCENTIVE CREDIT

Section

- 800. Exploration incentive credits
- 805. Credit for exploratory wells
- 810. Credit for geophysical work

Section

- 815. Filing of statements
- 820. Definitions

11 AAC 83.800. EXPLORATION INCENTIVE CREDITS. (a) If the commissioner receives a request for exploration incentive credit, the commissioner will, in his discretion, allow credits for expenditures for both exploratory wells and geophysical work against:

- (1) oil and gas royalty payable in-value and rental payments payable to the state; or
- (2) taxes payable under AS 43.55.

(b) The period during which exploration incentive credits may be earned and used and the percent of the exploration expenditures that will be allowed for credits in a particular region will be established by the commissioner and will be announced no sooner than two years before the sale but in no event later than the date of the notice of sale. The period during which exploration incentive credits may be earned and used may be extended at the discretion of the commissioner. Exploration incentive credits may be assigned. A notice of assignment must be filed with the commissioner on forms prescribed by the department. (Eff. 11/9/79, Register 72; am 8/15/82, Register 83)

Authority: AS 38.05.020
AS 38.05.180

11 AAC 83.805. CREDIT FOR EXPLORATORY WELLS. Credits may be earned only for one well per sale tract as that tract is defined on the day of a competitive oil and gas lease sale. Actual footage drilled in exploratory wells may earn exploration incentive credits at a rate established by the commissioner. In place of credit for actual footage drilled, expenditures for other operations related to the well will be considered for credit in the following manner:

(1) The cost of constructing and preparing the drilling location will be credited on a case-by-case basis at the discretion of the commissioner, who will determine the specific costs applicable to the exploratory well.

(2) Credits for other costs incurred by the lessee when drilling the exploratory well will also be considered on a case-by-case basis.

(3) At the request of the commissioner, the lessee shall submit all cost information necessary to determine the accuracy of the requested credits. If more than one company participates in drilling the exploratory well, then credit will be allowed in proportion to the participation in the drilling cost of the well. (Eff. 11/9/79, Register 72; am 3/30/84, Register 89)

Authority: AS 38.05.020
AS 38.05.180

11 AAC 83.810. CREDIT FOR GEOPHYSICAL WORK. (a) Geophysical exploration costs may be credited at a rate approved by the commissioner in the following manner:

(1) If the applicant desires credit for geophysical work, copies of the geophysical data obtained during the credit time period must be submitted to the commissioner within 90 days after completion of collection and processing of data.

(2) The commissioner will inspect the information submitted to ensure that the geophysical work was conducted according to accepted standards of geophysical practice before granting credits.

(3) The applicant is responsible for submitting correct information, for advising the state of any erroneous data previously submitted, and for correcting all errors in the geophysical information.

(b) Credits may be considered for geophysical work performed during the two seasons before the scheduled sale date.

(c) Geophysical information which accompanies an application under 11 AAC 83.815 for geophysical exploration incentive credits, including information submitted under (a)(1) - (3) of this section, will be made public 30 days after the lease sale date. (Eff. 11/9/79, Register 72; am 3/18/83, Register 85)

Authority: AS 38.05.022
AS 38.05.180

11 AAC 83.815. FILING OF STATEMENTS. (a) Applications for determinations of total exploration incentive credits must be signed and notarized by the lessee or its authorized representative and contain a statement attesting to the truth and accuracy of the information submitted. Applications must be submitted in triplicate to the commissioner and must include an accounting of expenditures and the date the expenditure was made.

(b) Applications for geophysical work credits must be signed and notarized by the person performing the work or his authorized representative and contain a statement attesting to the truth and accuracy of the information submitted. Applications must be submitted in triplicate to the commissioner and contain copies of the required geophysical information.

(c) The commissioner will, in his discretion, request additional information if an application contains insufficient information to determine the accuracy of the request for credit.

(d) Once exploration incentive credit is granted by the commissioner, the commissioner will certify to the grantee the amount of the credit, the work for which the credit was given, the period during which it may be (or has been) earned, and the period during which it may be applied.

(e) Approved credits, when used, must be reported on the monthly royalty or tax payment statement or on the yearly rental payment statement against which they are being applied. (Eff. 11/9/79, Register 72)

Authority: AS 38.05.030
AS 38.05.180

11 AAC 83.820. DEFINITIONS. Unless the context clearly requires a different meaning, as used in 11 AAC 83.800 - 11 AAC 83.820

(1) "commissioner" means the commissioner of the Department of Natural Resources, State of Alaska;

(2) "exploratory well" means a well drilled for the purpose of oil and gas exploration that

(A) is located three miles or more from any other well drilled for oil and gas with all distances measured as the horizontal distance between exploration targets, or

(B) is within three miles from a well drilled for oil and gas, but tests potential hydrocarbon traps that the commissioner, after analyzing evidence submitted by the lessee and other information, determines constitute a distinctly separate exploration target;

(3) "geophysical exploration season" means one year;

(4) "geophysical information" means the raw field data and all information necessary to compute, process, and prepare the field data for geological interpretation; for seismic work, this data includes the standard processed sections that are stacked after filtering and correction for statics and normal moveout;

(5) "geophysical work" means all geophysical methods used in hydrocarbon exploration and for the determination of geologic hazards, including but not limited to seismic, gravity, magnetic and electromagnetic measurements;

(6) "tax" means payments due under AS 43.55 or its successor tax;

(7) "actual footage drilled" means the well's measured depth, and may include sidetracking or redrilling necessary to reach the originally proposed bottom-hole location. (Eff. 11/9/79, Register 72; am 3/30/84, Register 89)

Authority: AS 38.05.020.
AS 38.05.180

ENCLOSURE 22

ARCO Alaska, Inc.
Post Office Box 100360
Anchorage Alaska 99510-0360
Telephone 907 265 6511

J. K. (Ken) Thompson
President

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OCT 25 1994

DIVISION OF OIL & GAS

October 21, 1994

CONFIDENTIAL Confidential information removed from this copy by DNR

Mr. Harry Noah, Commissioner
State of Alaska
Department of Natural Resources
400 Willoughby Avenue, 5th Floor
Juneau, Alaska 99801-1796

RE: Application for Exploration Incentive Credits
Fiord No. 3 and Alpine No. 1 (Proposed Exploratory Wells)
ADL-384214 & ADL-380075

Dear Commissioner Noah:

ARCO Alaska, Inc., on behalf of itself, Union Texas Petroleum Alaska Corporation and Anadarko Petroleum Corporation, does hereby make an Application for Exploration Incentive Credits for the proposed drilling of the Fiord No. 3 and Alpine No. 1 wells on ADL-384214 and ADL-380075, respectively, as further set forth on Attachment "1." This Application is made pursuant to AS 41.09.100, enacted by the Alaska Legislature earlier this year (1994 SLA Ch. 39; Senate Bill 151).

As you know, that legislation provides that the DNR commissioner "may extend to a qualified applicant an exploration incentive credit for each of the following activities performed on land in the state, regardless of whether the land is state-owned land: ... (3) drilling an exploratory well." AS 41.09.100(a), (emphasis added).

ARCO Alaska, Inc. believes that authorizing an exploration incentive credit ("EIC") for the Fiord No. 3 and Alpine No. 1 well(s) would be an excellent opportunity for the state to send a message of encouragement to the few companies remaining active in exploration of Alaska's lands. It would also be consistent with the

Enclosure 22

Mr. Harry Noah, Commission
October 21, 1994
Page 3

Under the statute, the Application must be approved prior to drilling (AS 41.09.100(c)(1)), may not exceed 50% of eligible costs relating to activities on state-owned land (AS 41.09.100(e)), and may not exceed \$5,000,000.00 per eligible project (AS 41.09.100(f)). AAI hereby requests approval on or before December 1, 1994 from the Department of Natural Resources for a EIC of 50% of the actual costs to drill and potentially evaluate the Fiord No. 3 and Alpine No. 1 well(s).

Should you have any questions or require additional information, please call Mark Landt at 265-1579. We appreciate your consideration in this matter.

Sincerely,



J. K. Thompson

CORRECTION

**THE FOLLOWING DOCUMENT(S)
HAVE BEEN REFILMED TO
ASSURE LEGIBILITY OR PAGINATION**



Rev. 6/98

Central Microfilm Services
Department of Education
State of Alaska

ARCO Alaska, Inc.
Post Office Box 100360
Anchorage Alaska 99510-0360
Telephone 907 265 6511

J. K. (Ken) Thompson
President

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OCT 25 1994



October 21, 1994

DIVISION OF OIL & GAS

CONFIDENTIAL

Confidential information removed from this copy by DNR

Mr. Harry Noah, Commissioner
State of Alaska
Department of Natural Resources
400 Willoughby Avenue, 5th Floor
Juneau, Alaska 99801-1796

RE: Application for Exploration Incentive Credits
Fiord No. 3 and Alpine No. 1 (Proposed Exploratory Wells)
ADL-384214 & ADL-380075

Dear Commissioner Noah:

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As you know, that legislation provides that the DNR commissioner "may extend to a qualified applicant an exploration incentive credit for each of the following activities performed on land in the state, regardless of whether the land is state-owned land: ... (3) drilling an exploratory well." AS 41.09.100(a), (emphasis added).

ARCO Alaska, Inc. believes that authorizing an exploration incentive credit ("EIC") for the Fiord No. 3 and Alpine No. 1 well(s) would be an excellent opportunity for the state to send a message of encouragement to the few companies remaining active in exploration of Alaska's lands. It would also be consistent with the

Mr. Harry Noah, Commission
October 21, 1994
Page 2

Governor and Legislators' stated goal of encouraging resource development.

We understand that DNR is hesitant to use the EIC process enacted by AS 41.09.100-190 for state-leased lands that could have been leased with EIC's under AS 38.05.180(i). We believe that interpretation would deprive the state of its most significant opportunity to provide meaningful encouragement of exploration, particularly for the North Slope.

We see nothing in AS 41.09.100-190 to indicate that the new EIC program cannot be used to promote exploration of any lands in the state, whether leased under AS 38.05.180 or not. Indeed, as noted above, AS 41.09.100(a) expressly applies to "land in the state, regardless of whether the land is state-owned land", and AS 41.09.100(e) specifies the maximum EIC for "activities performed on state-owned land."

The state owns most of the central North Slope acreage, and the state's historic practice is to lease its most prospective acreage first. Given the ongoing exodus of exploration companies from Alaska, an interpretation of AS 41.09.100 that limits its EIC's to lands not leased under AS 38.05.180 would most likely turn the program into one that is rarely used on the North Slope.

The new EIC program appears to present the state with an opportunity to encourage exploration where it may have failed to do so before. The low interest by bidders at the last sale (Sale 75A) indicates that it would now be appropriate for the state to provide additional encouragement of Colville exploration activities.

The Colville High is a geologically complex area, in which exploration is expensive, with decidedly mixed results to date. The EIC program of AS 41.09.100 could be used to provide strong incentive to continue to explore this area, which is one of the last opportunities on state acreage to discover reserves producible through TAPS.

Mr. Harry Noah, Commission
October 21, 1994
Page 3

Under the statute, the Application must be approved prior to drilling (AS 41.09.100(c)(1)), may not exceed 50% of eligible costs relating to activities on state-owned land (AS 41.09.100(e)), and may not exceed \$5,000,000.00 per eligible project (AS 41.09.100(f)). AAI hereby requests approval on or before December 1, 1994 from the Department of Natural Resources for a EIC of 50% of the actual costs to drill and potentially evaluate the Fiord No. 3 and Alpine No. 1 well(s).

Should you have any questions or require additional information, please call Mark Landt at 265-1579. We appreciate your consideration in this matter.

Sincerely,



J. K. Thompson

ENCLOSURE 23

Position Paper
Department of Natural Resources
Exploration Incentive Credit Legislation
HB 200 & SB 151

The Exploration Incentive Credit Bill extends a program that already exists on State lands to all lands in the State. It provides a means for the State to obtain exploration data to which it would not normally be entitled. It may also encourage exploration on lands that will enhance the exploration of adjacent or nearby State lands.

Exploration Incentive Credits (EICs) are currently offered by the State as a means to encourage exploration on State lands. Under AS 38.05.180(i), the Commissioner of Natural Resources may authorize the use of incentive credits to encourage exploration of state leases through either geophysical work or the drilling of a well. Geophysical EICs can be earned if the work is performed during the two seasons immediately preceding an announced lease sale on land included within the sale area, and if the geophysical work is made public following the sale. Drilling EICs are based on the footage drilled and the region in which the well is situated. The decision whether or not to offer credits is sale specific and is determined by evaluating the perceived geologic potential of the sale area as well as the perceived cost of exploration.

Under the current program, credits may not exceed 50 percent of the cost of drilling or geophysical work. Credits may be used during a limited period established by the commissioner and may be assigned during that period. Credits may be applied against oil and gas royalties and lease rentals or taxes payable under AS 43.55. A credit must not exceed 50 percent of the payment toward which it is being applied. Amounts due the Alaska Permanent Fund must be calculated before the application of credits.

Governor Hickel's proposal in HB 200 and SB 151 is to expand the current EIC program to all areas of the state, with certain modifications and restrictions. This new legislation provides an amount of \$50 million that may be used over a period of ten years, with each individual project capped at \$5 million. Credits of up to 50 percent on state-owned land and 25 percent on non state-owned land will be allowed. In contrast, the current EIC program has no time limit and no cap. The new legislation also provides for credits to be applied against income and other taxes in addition to the severance tax. The credits remain transferable under the provisions of this bill and, as with the current plan, amounts due the Permanent Fund must be calculated prior to application of any credits.

All data acquired under the EICs must be submitted to the commissioner. Well data will be held confidential for 24 months after submission, but no extension of this period of confidentiality will be allowed (i.e. all well data will become public 24 months after submission unless the company gives permission to release it sooner). Geophysical data will be allowed to be shown, but not transferred to, any interested party.

The Governor recognizes that activities on lands adjacent to, or nearby, State lands may significantly affect State land. This new legislation allows the commissioner discretion to provide credits to obtain data that the State otherwise would not be able to get. The State, by statute, can now get all seismic data gathered on State land only—but has no mechanism to obtain data on non-state owned land. The data obtained as a result of this legislation will enhance our knowledge of State lands, and the geophysical data may be used as a marketing tool to attract investors to State land.

Bill aids search for oil

House OKs measure to pay for expenses

By IAN MADER
The Associated Press

JUNEAU — The state could pay much of a company's costs of oil exploration on unleased land in return for the resulting geological information, under a bill the House passed Wednesday.

The bill is one of two Hickel administration measures designed to get the state's oil reserves explored faster. It aims to collect information that could help promote drilling in, unexplored basins, especially in the Interior.

The proposed credit program could pay up to 50 percent of exploration costs on unleased state land, and 25 percent of costs on other land. The state could spend up to \$30 million during the 10-year program. No project could get more than \$5 million.

The natural resources commissioner would decide how much credit to award in each case, depending on how much the state stood to gain. Exploration on private land could shed light on prospects for nearby state land, state officials say.

"We could offer a number of dollars per foot for the well drilled," said Ken Boyd, deputy director of the Division of Oil and Gas. "If it's too far from state land, we would say, 'No, we're

OIL: House OKs money to help hunt

Continued from Page B-5

really not interested.'"

The bill was introduced by Gov. Wally Hickel and passed the Senate last year. It passed the House 37-2, and was to be returned to the Senate for agreement with changes.

The legislation originally would have authorized \$50 million for the program. The House also added a provision to disqualify companies that are in debt to the state.

Boyd said several Native regional corporations, including Doyon Ltd. and Cook Inlet Region Inc., were interested in using the credits to explore land they own in Interior Alaska. Companies that specialize in speculative geophysical work and sell their data to oil companies also would use the incentives, Boyd said.

Information gathered under the program could generate interest in the state's oil lease offerings, Boyd said.

State law already allows credits for up to 50 percent of exploration on leased lands in return for speedy exploration. Credits above 30 percent never have been awarded, Boyd said.

Rep. John Davies, D-Fairbanks, said some of the credits probably would be higher than needed to encourage exploration.

"I think the state is making a lot of concessions to the industry as it is," Davies said. "We just gave them another major exploration incentive bill. I think that should be enough for this year."

Please see Page B-6, OIL

DEPARTMENT OF NATURAL RESOURCES

OFFICE OF THE COMMISSIONER

WALTER J. HICKEL, GOVERNOR

P.O. Box 107005

Anchorage, AK 99510-7005

PHONE: (907) 782-2483

FAX: (907) 562-4871

400 WILLOUGHBY AVENUE

JUNEAU, ALASKA 99801-1798

PHONE: (907) 465-2400

FAX: (907) 465-3888

November 18, 1994

J. K. Thompson, President
ARCO Alaska, Inc.
P. O. Box 100360
Anchorage, Alaska 99510-0360

Dear Mr. Thompson:

I am responding to your letter of October 21, 1994, in which you requested my pre-approval of Exploration Incentive Credits under AS 41.09.100 for the drilling of proposed wells Fiord No. 3 and Alpine No. 1. For the reasons set forth below, I must deny your request.

AS 41.09.100 was not intended to apply to the drilling of wells on state leased lands. The language of the bill itself notes that AS 41.09.100 is "...an incentive program distinct from the exploration incentive credit authorized by AS 38.05.180(i)..." (emphasis added). AS 38.05.180(i) allows the commissioner the discretion to use incentive credits on leased lands by announcing their availability prior to the lease sale, not afterwards. It allows the commissioner the option of using EICs to encourage exploration and development in those areas in which he deems the assistance to be in the state's interest.

In making EICs available to all competitive bidders before a lease sale under the provisions of AS 38.05.180(i), the commissioner maintains a level playing field. All bidders are aware of the availability of the EICs and of the terms under which they may be earned, thus enabling everyone to make an informed decision regarding their competitive bid. Making EICs available selectively to some lessees and not to others who had bid competitively under the same terms would raise serious issues of fairness.

AS 41.09.100, on the other hand, was always intended to apply only to those areas within the state where the Department of Natural Resources would not otherwise receive data from the drilling of wells or the gathering of geological or geophysical data. In other words, AS 41.09.100 was designed to encourage exploration of adjacent private and federal lands where the state is not entitled to receive data, as well as on certain unleased state land. The legislative record on this point is quite lengthy. Ken Boyd, Deputy Director of the Division of Oil and Gas, testified before the House Finance Committee on April 24, 1994, that "...it (CS SB151) would provide a means for the State to obtain exploration data to which it would

Enclosure 23

not normally be entitled..." Representative Joe Green, testifying before the House Judiciary Committee on March 25, 1994, stated that "...this bill (CS SB151) applies to unleased State land and private land..."

I have enclosed copies of the department's then contemporaneous Position Papers for HB 200 and SB 151, copies of two then contemporaneous articles from the Anchorage Daily News noting the restriction to unleased state lands, and finally, a copy of a table prepared by the department and distributed to legislators at hearings on the bills. The table differentiates the provisions of AS 38.05.180(i) and CSSB 151, explicitly noting the applicability of CSSB 151 to "unleased state land and private land".

While numerous EIC-eligible leases have been issued in the vicinity of the Colville Delta, the department's pre-sale analysis for both Sales 75 and 75-A suggested that EICs were not appropriate for those sales. I believe that the pace of subsequent exploration in that area confirms the willingness of lessees, including ARCO and its partners, to explore the area without additional financial support of the state.

You note in your letter that there was low interest by bidders at Sale 75-A and, therefore, it would be appropriate to provide additional encouragement of Colville exploration activities. In reviewing the records I find that Sale 75-A results indicate high, not low interest in that area. Sale 75-A records indicate that all eleven tracts offered in that sale were leased, either by Atlantic Richfield, a partnership of Atlantic Richfield and B.P., or by Union Texas Petroleum Alaska Corp.

Less than ten months before Sale 75-A was held, the department held Sale 75. That sale, which offered acreage surrounding the Sale 75-A acreage, also attracted strong bidder interest. Seven bidders exposed more than \$13.0 million in high bonus bids on 55 of the 90 tracts offered in that sale. I do not believe the results of either of these sales indicate "low interest."

Finally, Section 2 of AS 41.02.100 states that "the commissioner shall proceed to adopt regulations necessary to implement this act." While the Division of Oil and Gas and the Department of Law are proceeding with the writing of regulations, they are not yet complete. An early draft is currently under review by the Department of Law. The draft regulations will then be sent out for public review and comment. It is likely that one, or more, public hearings will be held. The regulations must then be submitted to the Lieutenant Governor for approval. This process cannot be completed by December 1st.

J. K. Thompson

-3-

November 18, 1994

In closing, it is my opinion that this administration has been committed to encouraging exploration and development, and it remains so.

Sincerely,



Harry A. Noah
Commissioner

Enclosures: as stated

Ken Boyd

Comparison of Existing and Proposed Exploration Incentive Credit Programs

EXISTING PROGRAM **AS 38.05.180(1)**

PROPOSED PROGRAM **CSSB 151**

Applies to

Specific Leased Land at the
discretion of the commissioner

Unleased State Land
& Private Land

Dollar Limitation

No Cap

\$30M Total/\$5M per Project

Sunset

No Time Limit

Sunsets in 10 years

Confidentiality

Extended Confidentiality for
wells may be allowed

No Extension
2 years max

Credit Allowance

Max of 50% of eligible costs

Max of 50% on State Land/
25% on Private Land

Credit Applies To

Severance Taxes only

All Taxes

No liquidated debt

Senate OKs remote-oil subsidy

By IAN MADER
The Associated Press

JUNEAU — The Senate has passed a bill that would allow the state to promote oil exploration on unleased lands by subsidizing up to 50 percent of a company's exploration costs.

The credits could be used to make it more attractive to explore in remote, untapped areas, particularly basins in interior Alaska, state officials say.

The amount paid by the state would be decided by the natural resources commissioner on a case-by-case basis, with no single project getting more than \$5 million. The state now offers such credits on leased lands in

exchange for speedy exploration.

Some environmentalists say the state should not be subsidizing any oil company activity. They also say they fear oil development in the Interior could cause major environmental problems.

Senate Bill 151, requested by Gov. Wally Hickel, passed 14-6 without debate Thursday, and was to be sent to the House pending a possible reconsideration vote.

The state would receive information from all such exploration projects, regardless of whether they are on state land. The state now is entitled to see

such data only for test drilling and seismological work on state land.

Ken Boyd, deputy director of the state Division of Oil and Gas, said the credits could be awarded based on how much the state stood to gain from the information, which could shed light on the prospects of nearby land.

The state would be able to offer up to 50 percent of the cost of exploration on state-owned land, and up to 25 percent on other land.

David van den Berg of the Northern Alaska Environmental Center in Fairbanks said he is

wary of any subsidy for oil companies.

"This establishes a potentially ugly precedent," he said. "Our basic reaction to incentives is: Give incentives to other companies, too. Ranching cockroaches could probably be viable with such incentives."

Environmentalists are less worried about the effects of the exploration than the effects of a discovery, van den Berg said.

"I think they would be conscientious about leaving a small footprint. But to us, it just means if you find stuff out in Minchumina, where's the nearest pipeline? What's going to happen then?"



ENCLOSURE 24

COOK INLET DISCOVERY ROYALTY APPLICATIONS

<u>Name of Well</u>	<u>Lessee (present names)</u>	<u>ADL Number</u>	<u>Date of Discovery</u>	<u>First Affidavit or claim of discovery</u>	<u>Date of written decision granting discovery royalty</u>	<u>Effective date of the 10-year discovery royalty</u>	<u>Commencement of commercial production</u>	<u>Date 12 1/2% royalty replaced 5% discovery royalty rate</u>	<u>Period royalty actually reduced</u>
Falls Creek Unit No. 1	Chevron ARCO	00590	4/10/61	12/3/63	2/18/64	5/1/61	None	No royalty ever paid	Never used
Middle Ground Shoal No. 1	AMOCO Getty Phillips	17595	6/10/62	11/12/62	1/15/63	6/10/62	5/66	6/10/72	6 years 1 month
Cook Inlet State No. 1	Phillips	17589	8/21/62	11/12/62	11/24/64	9/1/62	3/69	9/72	3 years 6 months
Beluga River Unit No. 1	Chevron ARCO Shell	17599	12/1/62	9/17/63	12/19/62	1/1/63	3/68	1/73	4 years 10 months
Granite Point No. 1	Mobil Union	18761	5/16/65	5/21/65	9/14/65	6/1/65	5/67	6/75	8 years 1 month
Trading Bay No. 1-A	Union Marathon	18731	5/23/65	6/18/65	8/27/65	6/1/65	1/67	6/75	8 years 5 months
Trayling No. 1-A	Union Marathon	17594	9/29/65	10/28/65	1/19/82	10/1/65	10/67	10/75	8 years 1 month
Nichols Creek State No. 1	Tenneco Superior	17598	4/28/66	5/23/66	8/19/66	5/1/66	10/68	No production after 1972	About 4 years

APPLICATIONS DENIED

<u>Name of Well</u>	<u>ADL Number</u>
Trading Bay No. 1 and No. 2	17597
Shoal Middle Ground Shoal	18754
W. Foreland Unit No. 3	18777
Redoubt Shoal No. 2	29690
Trading Bay State No. 1	35431

ENCLOSURE 25

**NORTH SLOPE
DISCOVERY ROYALTY APPLICATIONS**

<u>Lease ADL</u>	<u>Well Name</u>	<u>Field Name</u>	<u>Applicant</u>	<u>Date of Application</u>	<u>Status of Application</u>
28303	Prudhoe Bay State #1	Prudhoe Bay	ARCO	3/12/68	Granted
25633	Ugnu #1	Kuparuk	ARCO-BP	4/7/69	Granted
34633	Sag Delta #4	Endicott	BP	2/14/78	Granted
34635	Niakuk #5	Niakuk	BP	4/7/85	Granted
28297	Pt. McIntyre #3	Pt. McIntyre	ARCO	5/12/89	Granted
25906	Milne Point G-1	Milne Point	Conoco	12/7/89	Denied

Note:

Between 1968 and 1977 nine additional notice of discovery applications were filed, but the applicants never completed the full application procedure. Those nine applications are now expired.

ENCLOSURE 26



Tom Painter
Division Manager

Conoco Inc.
3201 C Street
Suite 200
Anchorage, AK 99503

September 7, 1989

Mr. James Eason
Director, Division of Oil and Gas
Department of Natural Resources
P. O. Box 7034
Anchorage, AK 99510-7034

RECEIVED
SEP 08 1989
DIV. OF OIL & GAS
DIRECTOR'S OFFICE

Dear Mr. Eason:

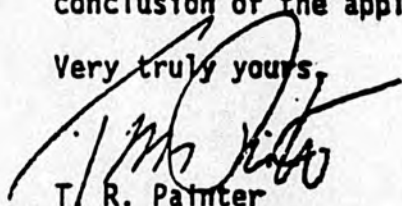
Pursuant to paragraph 12 of Lease ADL 25906 and 11 AAC 83.210(a), Conoco Inc. is submitting the attached Statement of First Discovery of Oil and Gas in Commercial Quantities in a Geologic Structure precedent to filing an application for discovery royalty for ADL 25906.

As indicated in the attached Statement and Exhibits, oil and gas has been encountered in sufficient showing in well no. G-1 to cause Conoco, a reasonable and prudent operator, to conduct further operations to complete said well in the discovery zone so that the well can be tested for potential oil or gas production in commercial quantities.

As required in 11 AAC 83.210(b), Conoco will undertake production tests in well no G-1 to establish that oil and gas has been discovered in commercial quantities. This testing will take place in the latter half of September, 1989, and we will furnish you sufficient notice and transportation (if requested) for a representative of your department to witness the testing. The geologic data required in 11 AAC 83.210(c) will be furnished in a timely manner.

If you need additional information concerning this Statement, please contact Al Hastings at 564-7650. Conoco respectfully requests that the information contained in the Statement and attached Exhibits remain confidential until the conclusion of the application and certification process.

Very truly yours,


T. R. Painter
Division Manager

AEH(jr)
File 500.58.08

Enclosure 26



Conoco Inc.
Suite 200
3201 C Street
Anchorage, AK 99503
(907) 564-7600

December 7, 1989

RECEIVED

DEC 11 1989

DIVISION OF OIL & GAS
ANCHORAGE, ALASKA

Mr. James Eason
Director, Division of Oil and Gas
Department of Natural Resources
P. O. Box 7034
Anchorage, Alaska 99510-7034

Dear Mr. Eason:

Pursuant to 11 AAC 83.215, Conoco Inc., as Operator of the Milne Point Unit and the sole Working Interest Owner of ADL 25906, requests discovery well certification for Well No. G-I. Conoco is in compliance with the filing provisions of 11 AAC 83.210.

It is my understanding that the Division of Oil and Gas will publish the appropriate notice of this application for discovery royalty. If you need additional information concerning this discovery royalty application, please contact me at 564-7601.

Attached to this application is a brief discussion of the Pre-Drilling Expectation and the Post-Drilling Verification for Well No. G-I. This discussion summarizes the other criteria that have been used in the more recent discovery royalty decisions.

Very truly yours,


David L. Bowler
Division Manager

AEH(jr)
Attachment
File 500.58.08

ENCLOSURE 27

DEPARTMENT OF NATURAL RESOURCES

DIVISION OF OIL AND GAS

PO BOX 7034
ANCHORAGE, ALASKA 99510-7034
PHONE: (907) 762-2553

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

April 4, 1991

DECISION

Conoco, Inc.	:	Oil and Gas Lease
Suite 200	:	ADL 28297
1201 C Street	:	Milne Point Unit
Anchorage, Alaska 99503	:	

MILNE POINT UNIT G-1 WELL DENIED CERTIFICATION
AS A DISCOVERY WELL

The Division of Oil and Gas (division) hereby denies certification of the Milne Point Unit G-1 well (G-1) as a discovery well. As discussed in greater detail below, this denial is based on the determination that overwhelming evidence, including that submitted by Conoco, Inc. (Conoco), clearly establishes that the G-1 well fails the essential "first discovery" requirement. The Shallow Oil Sands (SOS) and the larger structure of which it is a part was clearly discovered by previous exploration, and was publicly known.

Previous discovery is evidenced by: (1) several hundred earlier exploratory, Kuparuk River Unit and Milne Point Unit well penetrations which yield substantial electric log and/or core data to recognize the accumulation, and (2) previous successful flow tests of the accumulation from at least five other wells in the Milne Point Unit, and a pilot project within the Kuparuk River Unit. The division's evaluation is supported by the geological, geophysical, and engineering information submitted by Conoco, as well as by in-house data.