

**2/21/12
PRESENTATION:
ANALYSIS OF
ROYALTY
MODIFICATION BY
DNR**

<TARGET><BILL></BILL><SUBJECT>2-21-12 PRESENTATION
ANALYSIS OF ROYALTY MODIFICATION BY
DNR</SUBJECT><COMM>SRES27</COMM></TARGET>

*Senator G
Deputy Anna Tangeman*

**Senate Resources Committee
Joe Paskvan, Co-Chair
February 21, 2012**

Let's call the meeting to order.

Let the record reflect that it is _____ p.m. on Tuesday, February 21.

Let the record reflect that there is a quorum. Present are

- Co-Chair Wagoner
- Senator Stedman
- Senator Stevens
- Senator Wielechowski
- Senator French
- Senator McGuire
- And myself, Senator Paskvan

Today, the Senate Resources Committee has several items on the agenda:

1. First, from 3:30pm to approximately 5pm, we will have a discussion about ROYALTY MODIFICATION, FOCUSING ON THE ECONOMIC ANALYSIS, with the Department of Natural Resource's Division of Oil and Gas.
2. Beginning at approximately 4:55pm, Senator Wagoner will then chair a hearing on a few pieces of legislation. We need to start the bill hearing at this precise time so that Johanna Bales can offer testimony here before a 5pm Budget Subcommittee hearing in another room.

Welcome back, Mr. Barron. I understand that Commissioner Sullivan is on the teleconference and will offer the Committee some opening remarks.

Please introduce yourselves for the public record and then begin your testimony.

*Director
Bill Barron*



Senate Resources Committee

21 February 2012

William C. Barron
Director
Division of Oil and Gas

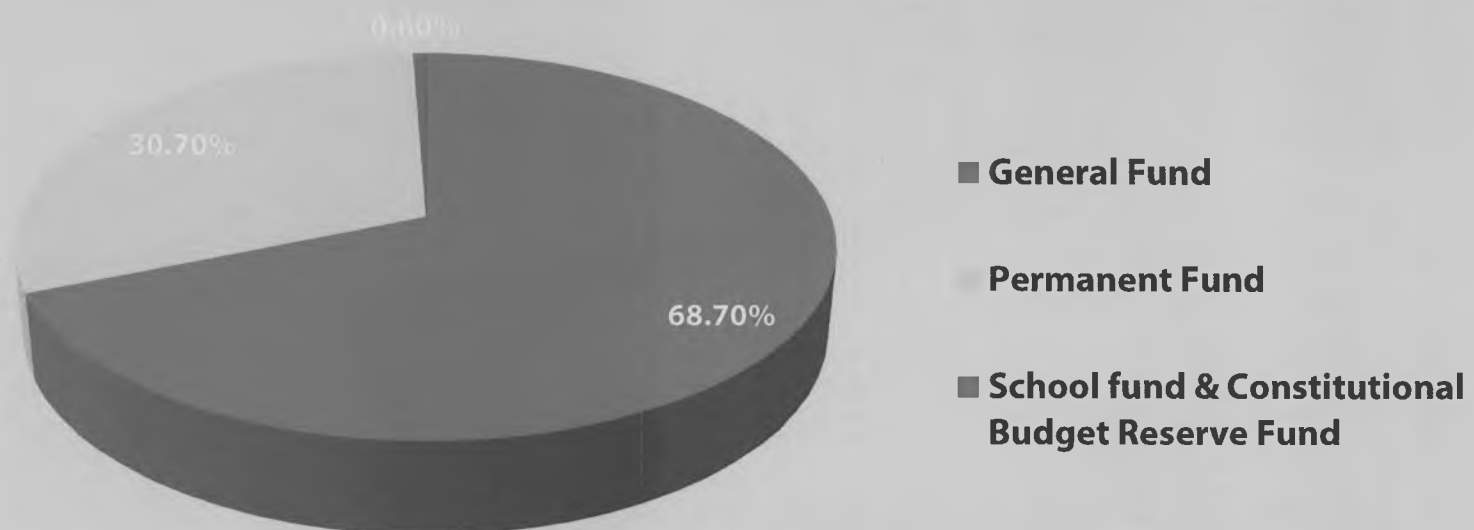




What is Royalty? How is it distributed?

ROYALTY: THE STATE'S SHARE of the product or profit reserved by the owner of land for permitting another to develop his land for oil or gas

FY 2012 (through January) Royalty Revenue Distribution





Unmodified Royalty Rates by Region

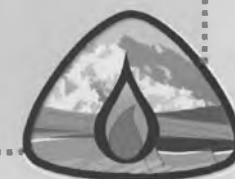
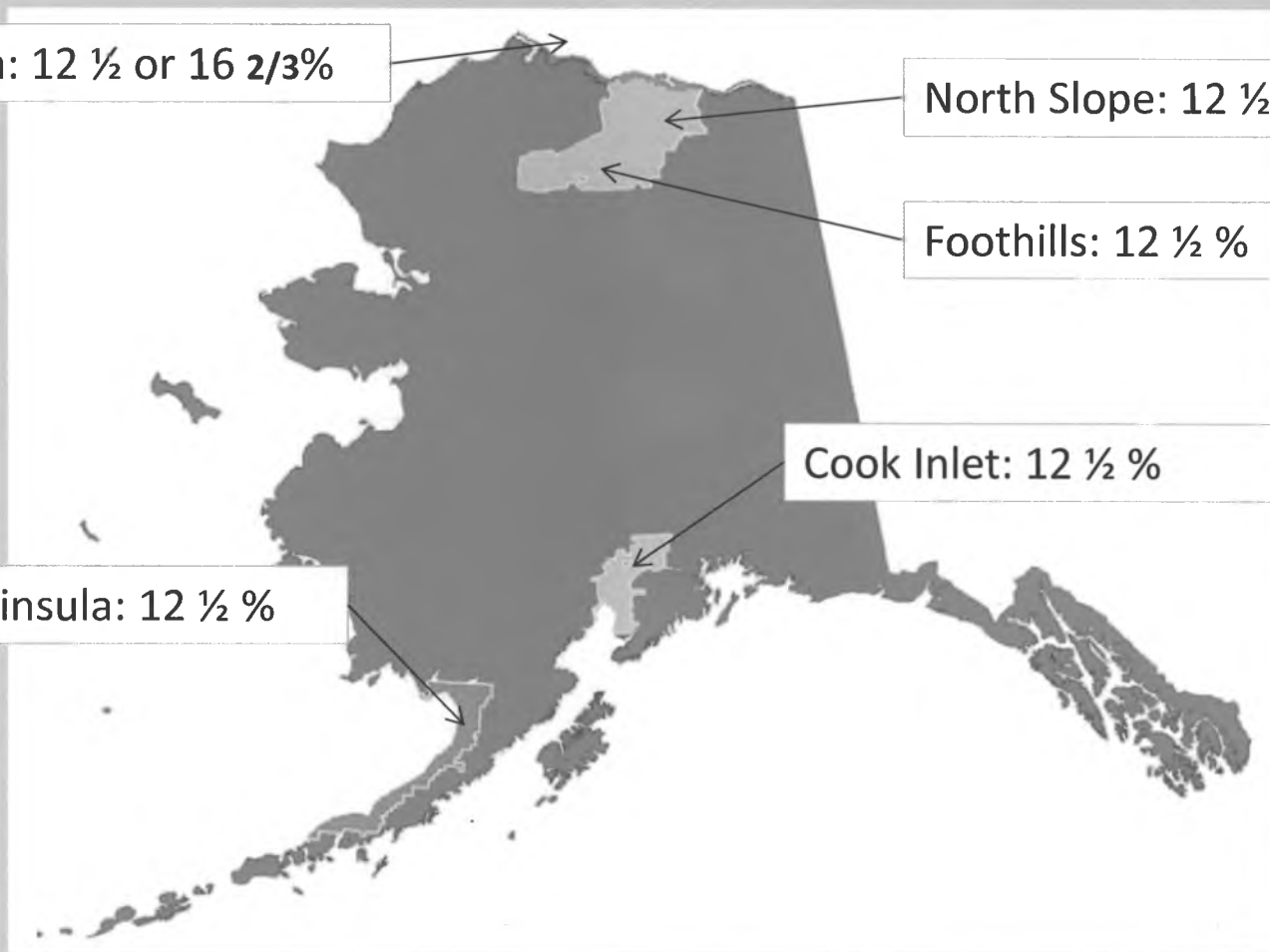
Beaufort Sea: 12 ½ or 16 2/3%

North Slope: 12 ½ or 16 2/3%

Foothills: 12 ½ %

Cook Inlet: 12 ½ %

Alaska Peninsula: 12 ½ %





History of Royalty Modification: Legislative Action

- Royalty modification statute is a long-standing statute
 - An exchange for pool or field development
 - Legislatively-created mechanism to increase field and pool production
- Recent amendments in 1995 (HB 207) & 2003 (HB 28)
 - 1995 amendment (House Bill 207):
 - Lowered state oil royalties to encourage production and raise them when economic conditions warranted it
 - Allows DNR to analyze three prongs of any decision about the economics of an oil field: 1) costs of development, 2) the volume of oil in the field, and 3) the price of oil in making royalty reduction.
 - Added “new fields and pools”
 - As the industry starts to go out into new frontiers, we are looking at developing smaller and smaller fields. (Commissioner Shivley)
 - 2003 amendments (House Bill 28):
 - Intended to modify the 1995 law
 - Spur development of uneconomical fields by setting forth a more understandable and workable modification process
 - Protecting the public's interest and maintain public's input
 - Push to get Liberty and Badami online





History of Royalty Modification: Circumstances Surrounding Amendments

- What was the product price at that time?
 - 1995 ~ \$15-18/barrel
 - 2003 ~ \$25-30/barrel
- What was going on in industry?
 - 1995:
 - Milne Point shut-in
 - Continued low oil prices
 - Only 1 new unit on North Slope since 1981 (North Star)
 - World-wide production declining due to industry consolidations and automobile efficiency and other Clean Air Act standards
 - 2003:
 - TAPS throughput dips below 1 million BOPD
 - Beginning of four year surge in North Slope unit approvals in 2001
 - Oil prices begin first climb since the 1980s moving above \$30/barrel
 - Virtually no use of royalty modification by industry in last 7 years





Royalty Modification

AS 38.05.180(j)

- Allows commissioner to modify royalty to allow for production from a field or pool under three conditions/scenarios:
 - Not in production
 - Field or pool must be sufficiently delineated
 - Field that would not otherwise be economically feasible
 - Royalty shall never be lower than 5%
 - Prolong economic life
 - As costs increase or price decreases... to make future production uneconomic
 - Royalty shall never be lower than 3%
 - Re-establish production
 - Royalty shall never be lower than 3%





Royalty Modification

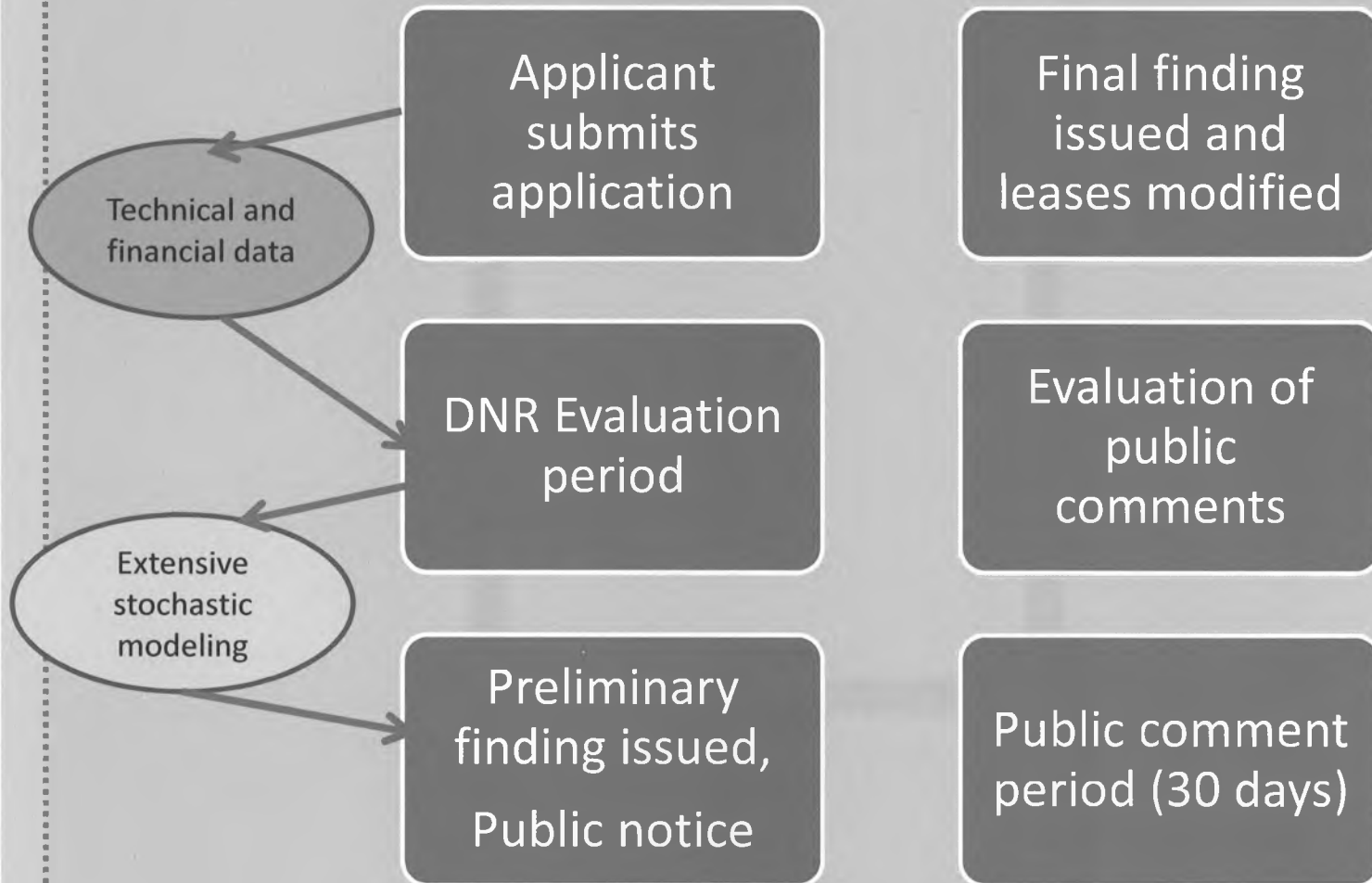
AS 38.05.180(j)

- Commissioner may not approve unless he determines that lessee makes a clear and convincing showing that relief is in the best interest of the state
 - Without royalty modification, oil or gas production from the field or pool would probably not proceed *i.e. - shut in*
 - Royalty modification is applied only to the point where investor is inclined to develop
- DNR may hire an independent contractor at the applicant's expense, for up to \$150,000 per application
 - Selected by lessee from contractor list provided by DNR
- Relief mechanism must adjust percentage based on a change in the price of oil or gas and may also be based on other relevant factors such as a change in production rate, projected ultimate recovery, development costs, and operating costs. AS 38.05.180(j)(1)(A)(3)





Application Review Process Map





Decision Parameters

Royalty modification is provided if it can be demonstrated that the project is uneconomic without royalty relief.

Calculations:

Use Expected Monetary Value (EMV) to determine project economics

Monte Carlo

Key Parameters :

- Price of oil
- Potential reserves and production rates
- Capital Expenditures (CAPEX)
- Operating Expenditures (OPEX)

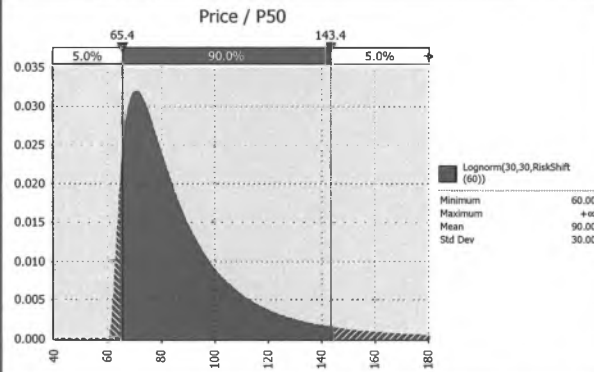
There is uncertainty associated with key parameters



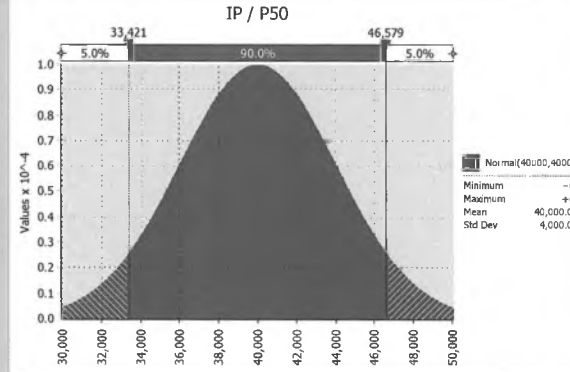
Modeling Uncertainty - Stylized Example

Input Distributions

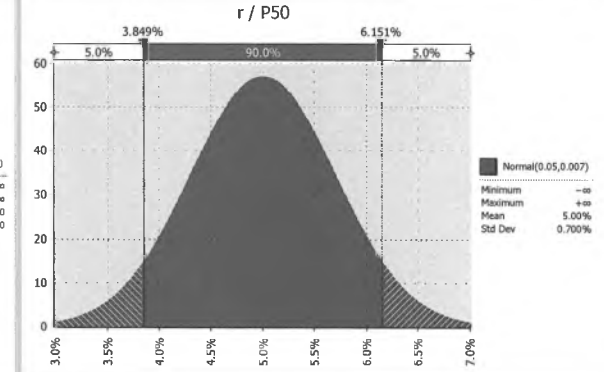
Price (\$/bbl)



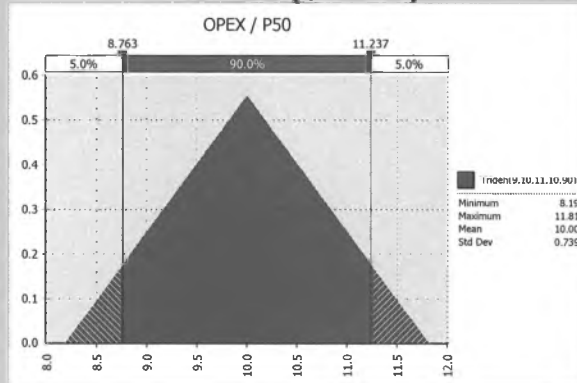
Initial Production (BOPD)



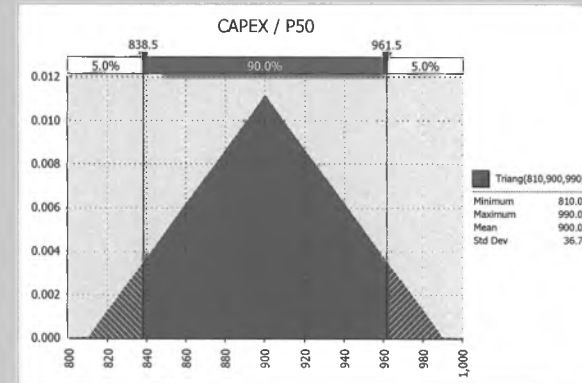
Production Decline (%)



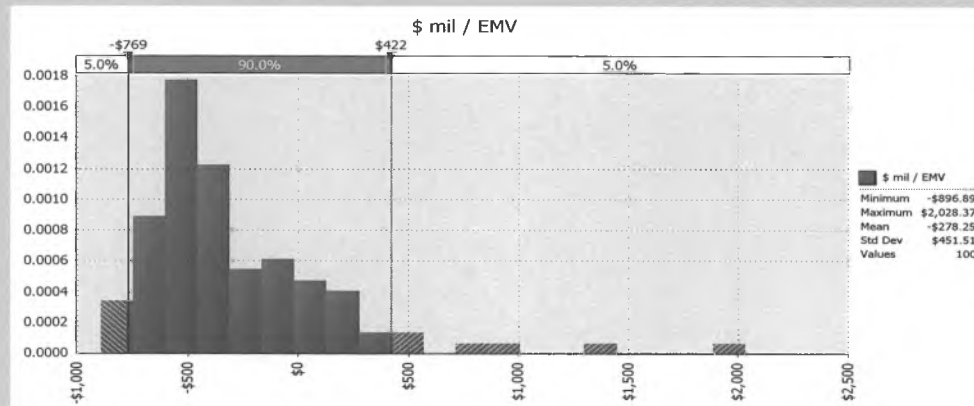
OPEX (\$MM)



CAPEX (\$MM)



EMV (\$MM)



Output Distribution



Royalty Modification Applications

- February 1995 BP application for Milne Point
 - Application explicitly made only to comply with BP's contract with OXY
- 1997 Unocal application for 10 platforms in Cook Inlet
 - Unocal did not continue to pursue application
- 1999 Phillips application for Tyonek Deep in Cook Inlet
 - Phillips withdrew the application

2036 Aikaitchug.





Royalty Modification Applications

- 2005 Pioneer Natural Resources application for leases in and near the Oooguruk Unit
 - Approval effective February 2, 2006
 - Royalty is reduced from 12.5% or 16.66667% to 5% on all production from the delineated reservoirs from the subject leases until NPSL payout.
 - Beginning on NPSL payout, royalty rates step-up to original royalty rates in four annual steps.
- 2006 Kerr-McGee application for leases in the Nikaitchuq and Tuvaag units
 - Denied October 31, 2006
- 2007 Chevron application for leases in the Ivan River and Stump Lake units
 - Chevron withdrew the application

Kenai area





Royalty Modification Applications

- 2007 ENI application for leases in the Nikaitchuq Unit
 - Approval effective January 30, 2008
 - Royalty modification can be triggered by either of two mechanisms.
 - Low price trigger: for 25 years after first commercial production, if ANS WC inflation adjusted price falls below \$42.64, royalty is modified to 5% on production from all subject leases from the reservoirs delineated in the application.
 - Low production trigger: between 18 months and 120 months after first commercial production, if production from all subject leases averages below 4,000 BOPD, royalty is modified to 5% no matter what oil prices are.





Summary

- Royalty modification is given in exchange for pool or field development
- Application must be for a pool/field – not projects
- Allows for production in new, shut-in, and existing fields/pools demonstrated to be economically unfeasible without royalty relief
- DNR uses Expected Monetary Value (EMV) to determine project economics
- Only 2 royalty modifications granted (Oooguruk and Nikaitchuq Units) 6 applications since 1996.
- Nikaitchuq royalty relief has never been realized – essentially serves as oil price insurance



Please answer the questions below, which were submitted to Commissioner Sullivan on 1/26:

Senator Paskvan is interested in learning more about DNR's economic analysis that is included in the Final Findings and Determination of the Commissioner of the Department of Natural Resources, regarding the Nikaitchuq Development Royalty Modification Application (see p. 19 – 20), which says, in part:

The DNR has determined that under the PPT and over the life of the project, KMG would pay, on a discounted basis, about \$120 million less in taxes than under the previous fiscal regime. The high capital expenditures for the Nikaitchuq project serve to offset other statewide income streams and lower the overall tax obligation for the corporation. KMG and its parent, Anadarko Petroleum Corporation, will realize very large profits from Alaska production if oil prices stay at current high levels over the next several years.

Simultaneously, high capital expenditures at Nikaitchuq will be taking place, resulting in lower net income statewide, offsetting statewide income dollar for dollar and generating "qualified capex" credits that reduce tax obligations. Additionally, at high prices the progressive element of the PPT will be in effect, further increasing taxes for KMG.

Capital investments in Nikaitchuq development offset income and result in a lower net tax liability to KMG. Other impacts PPT will have on this project are shown in Table 1 [attached, p. 20]. From the working interest owner's perspective, the new tax regime improves the NPV, IRR, and the profit to investment ratio for the Nikaitchuq development project. At the same time PPT is improving the economics for the working interest owners, the State of Alaska is giving up a significant amount of tax revenue for this project.

Some questions about this:

1. Why would Kerr-McGee (KMG) pay less under PPT than the previous fiscal regime (i.e., ELF), when PPT is generally understood to be a tax increase over ELF? If this is true, is it possible, then, that they would pay even less under ACES than PPT?
2. How is "over the life of the project ... on a discounted basis" a different analysis than, simply, the nominal and/or effective tax rate?
3. DNR said in the Final Findings above: "The high capital expenditures for the Nikaitchuq project serve to offset other statewide income streams and lower the overall tax obligation for the corporation." Is this statement equally true for other current projects on the North Slope today? Why or why not?
4. In 2006 when oil prices were ~\$60 per barrel, DNR found that: "KMG and its parent, Anadarko Petroleum Corporation, will realize very large profits from Alaska production if

oil prices stay at current high levels over the next several years." Is it the case, then, that KMG (or current operator) and its parent are currently realizing "very large profits" in 2012 since oil is, and has been, ~\$100 per barrel? Or have other factors materialized over the past few years that reduced their profit (ACES, higher opex, higher capex, for example)?

5. In the Final Findings above, DNR stated: "Simultaneously, high capital expenditures at Nikaitchuk will be taking place, resulting in lower net income statewide, offsetting statewide income dollar for dollar and generating 'qualified capex' credits that reduce tax obligations." How has ACES changed or not changed the accuracy of this analysis since it replaced PPT?
6. DNR said in 2006 that, "From the working interest owner's perspective, the new tax regime improves the NPV, IRR, and the profit to investment ratio for the Nikaitchuk development project." Is the same true for the working interest owners under the current ACES tax regime? That is, does ACES improve the NPV, IRR, and the profit to investment ratio for new project development on the North Slope? Why or why not? How can we know?
7. In 2006, DNR found that: "At the same time PPT is improving the economics for the working interest owners, the State of Alaska is giving up a significant amount of tax revenue for this project." Is this statement still true today with the ACES tax system in effect? That is, if you substitute "ACES" for "PPT" in the sentence above, is it still accurate? Why or why not?

Final Findings and Determination Nikaitchuq Royalty Modification
Economic Analysis, pages 13 – 16
January 11, 2008

1. It is understood that, “The ADNR decision framework is confidential.” Please tell the Committee what you can re: “It is designed to replicate the kind of framework used by industry for making prudent oil and gas investment decisions under uncertain conditional involving significant capital outlays and lengthy project lives.”
2. What do you mean by “prudent”? DNR mentions the “prudent-investor standard;” please elaborate on that concept. What does it mean? How is it applied? Ditto for “prudent-investor standards for economic feasibility.”
3. How does DNR determine what “is in the best interests of the state” (page 18, #4)?

Sen Paskvan requests detailed, substantive information about the economic analysis.

**Final Findings and Determination Nikaitchuq Development Royalty Modification
Economic Analysis, pages 17 – 20
October 30, 2006**

1. Please explain Economic Analysis, which begins on page 17, paragraph 1. Why does DNR believe "granting royalty modification should influence the behavior of the applicant" (i.e., what's the rationale)? How do you know if royalty modification influences the behavior of the applicant or not? Please elaborate.
2. What does DNR mean by forward-looking companies, sunk costs, and project sanctioning decision? Please describe each. *Bill Harting*
3. Please describe DNR's "own in-house economic model (DNR Model)." What is it? Who works on it? Is it accurate and effective? What, as specifically as you can describe, are the inputs and outputs? Please talk about the "assumptions and methods currently in use by the U.S. Minerals Management Service (MMS) for the Deep Water Royalty Relief Program (DWRR)."
4. Please discuss the concepts advanced on page 18, re: "a particular view of a projects economics," "40-year time horizon," "various financial metrics for the project including annual and cumulative discounted and undiscounted cash flow, years to payout, NPV, EMV, and IRR on investment, as well as state revenues." Why are these concepts important in evaluating royalty modification applications? What does this analysis tell you? Why is this analysis applied?
5. Please describe the Monte Carlo simulation employed by DNR. What is a Monte Carlo simulation? What are the inputs and outputs? What does it tell you?
6. DNR says, "Calculating risk weighted outcomes is critical to a full analysis of a project." Please describe "risk weighted outcomes" and how they are calculated by DNR. Why are they "critical to the full analysis of a project"?
7. Please describe annual netback price calculations, etc.

**Nikaitchuq Development
Royalty Modification
Application**

**Final Findings and Determination of the Commissioner
of the Department of Natural Resources**

**DENIAL OF MODIFICATION OF ROYALTY
FOR LEASES: ADLs 355021, 355024, 388571, 388572, 388574, 388575, 388577,
388578, 388580, 388581, 388582, 388583, 390615, and 390616**

October 30, 2006

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1. Request for Royalty Modification, Kerr-McGee, January 11, 2006.
2. Alaska Statute 38.05.180(j)
3. Nikaitchuq Development Area Map
4. Nikaitchuq Project Map
5. Economic Analysis and Internal Decision Process,
Cover page, (CONFIDENTIAL under AS 38.05.180(j) and
“Deliberative Process Privilege”)
The following attachments are included as attachments to the
Confidential Economic Analysis and Internal Decision Process

Econ One, Presentation to Legislature, August, 2005
“Presentation On Alaska Gas Pipeline Project, Investment
Decision-Making by Oil and Gas Companies”
Kerr-McGee Nikaitchuq Area Project Report, January 11, 2006
DNR Flow chart of decision process metrics, summary and
overview of mechanism.
DNR Model printouts to support confidential analysis

6. Applicant Submittals and Work Sessions.
7. Copy of Public Notice Affidavits
8. Public Comments

I. BACKGROUND

On January 11, 2006, Kerr-McGee Oil & Gas Corporation¹ (KMG) as operator of the Nikaitchuq Unit (NU) and on behalf of itself and ENI Petroleum Exploration Co. Inc. (ENI) submitted an application (Attachment 1) to the commissioner of the State of Alaska Department of Natural Resources (DNR) for royalty modification under AS 38.05.180(j)(1)(A) (Attachment 2). This Findings and Determination responds to the royalty modification application as required under AS 38.05.180(j)(11)(B).

KMG applied for royalty modification on 14 leases that overlie the Schrader Bluff and Sag River pools. They requested that the fixed royalty rate of 12.5 percent on the two Net Profit Share (NPS) leases, ADLs 355021 and 355024, and that the fixed royalty rate of 16.66667 percent on the 12 other leases, ADLs 388580, 388581, 388583, 388582, 390615, 390616, 388571, 388572, 388574, 388575, 388577, and 388578, be reduced to the minimum rate allowed, 5 percent, with the net profit rate to remain at 30 percent on the two NPS leases.

The commissioner published the Preliminary Findings and Determination and gave public notice of a 30-day public comment period that began on September 1, 2006, and closed at 5 p.m. October 2, 2006, with legal advertisements in the Anchorage Daily News, The Fairbanks News-Miner, and The Arctic Sounder (Attachment 7). The commissioner offered to appear before the Legislative Budget and Audit Committee to provide a review of the Findings and Determination, the Confidential Economic Analysis, and the administrative process, but no invitation for this briefing was received. The submitted data will be held confidential under AS 38.05.035(a)(9) at the request of the lessee and the Confidential Economic Analysis and Internal Decision Process will be held confidential under the Deliberative Process Privilege. This Final Findings and Determination is not appealable to the court.

II. SUMMARY OF KMG'S APPLICATION FOR ROYALTY MODIFICATION

A. Lease Summary

KMG applied for royalty modification on 14 leases. Twelve of the leases are committed to units. ADL 355024, an NPS lease, is committed in its entirety to the Kuparuk River Unit (KRU) and in part to the Kuparuk Participating Area (KPA). ADL 355021, also an NPS lease, is committed in its entirety to the Milne Point Unit (MPU) and in part to the MPU-KPA. Four leases are committed in their entirety to the Nikaitchuq Unit (NU), (ADLs 388580, 388581, 388582, 388583), and six are committed in their entirety to the Tuvaq Unit (TU), (ADLs 388571, 388572, 388574, 388575, 388577, 388578). The remaining two leases, (ADLs 390615 and 390616), are not committed to a unit and remain in their primary term. (Attachment 3)

¹ Kerr-McGee Oil & Gas Corporation was acquired by Anadarko Petroleum Corp. on August 11, 2006, and is now a wholly-owned subsidiary.

DNR issued ADL 355024 effective June 1, 1983, on Competitive Oil and Gas Lease Form No. DMEM-4-83 (NET PROFIT SHARE)(REVISED May 5, 1983) DNR 10-1113, with a primary term of 10 years, 12.5 percent fixed royalty rate, and 30 percent NPS for the state. Effective June 1, 1985, ADL 355024 was committed in part to the KRU and in part to the KRU-KPA. Effective June 16, 1988, ADL 355024 was committed in its entirety to the KRU (Third Expansion of the Kuparuk River Unit).

DNR issued ADL 355021 effective August 1, 1983, on Competitive Oil and Gas Lease Form No. DMEM-4-83 (NET PROFIT SHARE)(REVISED May 5, 1983) DNR 10-1113, with a primary term of 10 years, 12.5 percent fixed royalty rate, and 30 percent NPS for the state. Effective April 27, 1992, ADL 355021 was committed in its entirety to the MPU in the Third Expansion of the MPU. The Northwest Milne #1 well was drilled on ADL 355021 and effective August 5, 1994, the well was certified capable of producing in paying quantities, thereby extending the lease's primary term indefinitely. Effective June 4, 1994, the lease was committed in part to the MPU-KPA.

DNR issued ADLs, 388571, 388572, 388574, 388575, 388577, 388578, 388580, 388581, 388582, and 388583 on state lease form DOG 9609(REV 6/97), effective January 1, 1998, with a seven-year primary term and a 16.66667 percent royalty rate. Effective April 30, 2004, ADLs 388580, 388581, 388582, and 388583 were committed in their entirety to the NU, and effective August 21, 2004, ADLs 388571, 388572, 388574, 388575, 388577, and 388578 were committed in their entirety to the Tuvaq Unit extending the leases' terms beyond the primary term.

DNR issued ADLs 390615 and 390616 effective July 1, 2005, on state lease Form No. DOG 200204(REV10/03) with a seven-year primary term and a 16.66667 percent royalty rate.

As a result of assignments of working and royalty interest shares, KMG and ENI have established ownership positions in segments of the two NPS leases, ADLS 355024 and 355021. The royalty modification application is limited solely to the segments of these leases in which KMG and ENI retain working interest ownership (Attachments 1, 3 and 4).

ADL 355024 contains two horizontally differentiated segments, Segment 1 and Segment 2. Segment 1, the southern portion of ADL 355024, is not a part of the royalty modification application and KMG and ENI have no working interest in Segment 1. In Segment 2, commonly referred to as the Kigun portion of the lease, KMG retains a 54.74 percent working interest while ENI retains 44.8 percent. Armstrong Alaska and ExxonMobil each retain less than one percent working interest of Segment 2 only.

ADL 355021 contains three vertically differentiated segments, Segment 1, Segment A, and Segment B. KMG and ENI have no working interest ownership in Segment 1, which comprises the depth of the entire lease from the surface to 7,526 feet true vertical depth (TVD). Segment 1 is not part of the royalty modification application. Segment A,

referred to as Sag River, comprising the depth of the entire lease from 7,526 feet TVD to 9,507 feet TVD is owned by KMG (70 percent working interest owner), and ENI (30 percent working interest owner). Only Segment A of ADL 355021 is included in the royalty modification application. Segment B comprises the balance of the depth of the entire lease, from 9,507 feet to the center of the earth. KMG retains a 35 percent working interest ownership in this segment and ENI holds 15 percent. George Alan Joyce Jr. and Herbaly Exploration LLC hold 5 percent and 45 percent working owner interest respectively. Segment B is not part of the royalty modification application.

KMG and ENI retain 82.00 percent and 18.00 percent, respectively, of the six Tuvaq leases, ADLs 388571, 388572, 388574, 388575, 388577, 388578. The four Nikaitchuq leases, 388580, 388581, 388582, and 388583, and the two non-unitized leases, ADLs 390615 and 390616, are owned 70 percent by KMG and 30 percent by ENI.

B. Project Development History

In the 2003-2004 and 2004-2005 exploration/appraisal drilling programs KMG/Armstrong encountered accumulations of hydrocarbons in the area of the then proposed NU that included heavy oil and relatively good reservoir rock in the Schrader Bluff Formation and higher-quality oils, but worse reservoir rock in the Sag River Formation. KMG drilled six wells in the Nikaitchuq area in the 2004 and 2005 winter drilling seasons. During the first quarter of 2004, KMG drilled two exploration wells in the NU, the Nikaitchuq #1 and #2 wells to the east of the proposed TU. The Tuvaq #1 exploration well was also drilled to test the continuity of the Schrader Bluff reservoirs along with examining the potential of deeper horizons. Effective April 30, 2004, the NU was formed and effective August 21, 2004, TU was formed. Each Initial Plan of Exploration for these units was attached and made part of each unit agreement as Exhibit G.

The conclusions regarding the reservoirs and projected performance were derived from studies of the performance from similar reservoirs being developed by offsetting operators, evaluation of multiple exploration/appraisal wells on the Schrader Bluff and Sag River reservoirs drilled in 2004 and 2005, and extensive reservoir and commercial modeling. The confidential analyses of the proposed development were reviewed in meetings with the Division of Oil and Gas (DOG) in August 2005, and DOG held several working sessions with KMG throughout the fall. KMG submitted the Application for Royalty Modification for ADLs 355021, 355024, 388571, 388572, 388574, 388575, 388577, 388578, 388580, 388581, 388582, 388583, 390615, and 390616 on January 11, 2006.

The planned development incorporates the following:

- formation of a new unit possibly comprised of the area currently committed to the Nikaitchuq and Tuvaq units, surrounding acreage such as ADLs 390615 and 390616, and segments of ADLs 355021 and 355024 in which KMG has a working interest ownership;

- construction of a gravel pad with drilling, gathering, and production facilities on Oliktok Point near the existing ConocoPhillips Alaska Inc. seawater treatment facility;
- construction of a gravel drilling island near Spy Island tied back via a 3.8-mile subsea flow line and utility bundle to Oliktok Point for fluid processing;
- construction of a +/-14 mile pipeline from Oliktok Point to a tie-in near KRU DS-1Y pad for connection to the Kuparuk Transportation common carrier pipeline; and
- consideration of future modifications required to adjust facility configuration to accommodate actual results of well performance.

Development studies indicate that extended reach horizontal producing and injection wells required for pressure maintenance are needed to economically recover the hydrocarbons in place. The planned development would permit a relatively small footprint for centralized facilities and minimal well pads, thereby reducing environmental impacts to the region. Initial drilling will be from a 313,000-square-foot pad to be constructed at Oliktok Point. Existing roads will be used for access. The production facilities will be located on the same pad. A small gravel island is to be constructed shoreward of the barrier islands for future drilling. A subsea bundle containing a three-phase production line and multiple utility lines will be constructed to connect the gravel island to Oliktok Point to transport production to Oliktok Point and provide fuel, secondary recovery fluid, and power to the gravel island.

III. SUMMARY OF ROYALTY MODIFICATION AUTHORITY AS 38.05.180(j)(1)(A), (2), (3), (4)(A), (5)

A. Royalty Modification Requirements

AS 38.05.180(j)(1)(A) authorizes the DNR commissioner to provide for royalty modification on individual leases, leases unitized as described in (p) of this section (AS 38.05.180), leases subject to an agreement described in (s) or (t) of this section (AS 38.05.180), or interests unitized under AS 31.05 to allow for production from an oil or gas field or pool if:

1. the oil or gas field or pool has been sufficiently delineated to the satisfaction of the commissioner;
2. the field or pool has not previously produced oil or gas for sale; and
3. oil or gas production from the field or pool would not otherwise be economically feasible.

Under AS 38.05.180(j)(2), the commissioner may not grant a royalty modification unless the lessee or lessees requesting the royalty modification make a clear and convincing showing that a royalty modification meets the requirements of AS 38.05.180(j) and is in the best interests of the state.

B. Royalty Modification Terms

Under AS 38.05.180(j)(3) the royalty modification terms must provide for an increase or decrease or other modification of the state's royalty share by a sliding scale royalty or other mechanism that shall be based on a change in the price of oil or gas and may also be based on other relevant factors such as a change in production rate, projected ultimate recovery, development costs, and operating costs.

Under AS 38.05.180(j)(4)(A) a royalty modification may not be granted for the field or pool if the royalty modification would result in a royalty rate of less than 5 percent in amount or value of the production removed or sold from a lease or leases covering the field or pool.

Under AS 38.05.180(j)(5) a royalty reduction must include an explicit condition that the royalty reduction is not assignable without the prior written approval, which may not be unreasonably withheld, by the commissioner. The commissioner shall, in the preliminary and final findings and determinations, set out the conditions under which the royalty reduction may be assigned and may not grant a royalty reduction without an explicit condition that the royalty reduction is not transferable.

IV. DISCUSSION OF ROYALTY MODIFICATION REQUIREMENTS

A. Leases Are Eligible For Consideration

The leases meet the requirements for consideration. Six of the leases proposed for royalty modification are committed in entirety to the TU, four to the NU, one to the MPU, one to the KRU, and two are non-unitized leases. AS 38.05.180(j)(1) allows modification of royalty for individual leases and unitized leases.

B. Reservoir Description and Delineation

1. Introduction To Reservoir Description

The commissioner may grant royalty modification to allow for production from an oil or gas field or pool if the oil or gas field or pool has been sufficiently delineated to the satisfaction of the commissioner. For purposes of this decision, the KMG Nikaitchuq #1 is considered the type well for both the Schrader Bluff and Sag River pools. Nikaitchuq #1, completed April 1, 2004, was the first well drilled within the NU and proved potential in both the Sag River and Schrader Bluff formations. The Schrader Bluff pool encompasses both the N and OA Sands and is defined in Nikaitchuq #1 as the interval between 4,865 feet measured depth (MD) (3,999 feet subsea TVD) and 5,096 feet MD (4,174 feet subsea TVD). The Sag River pool is defined in Nikaitchuq #1 as the interval between 10,359 feet MD (8,631 feet subsea TVD) and 10,738 feet MD (9,039 feet subsea TVD).

The Nikaitchuq area for which royalty relief is sought lies offshore in the Beaufort Sea in the vicinity of Spy Island, approximately three miles north of Oliktok Point. The Nikaitchuq area is north of and contiguous with the northern edges of the KRU and MPU.

The MPU field lies to the south-southeast of the proposed unit and produces oil from the Schrader Bluff, Kuparuk, and Sag River formations.

2. Early Exploration History of the Area

Two early key exploration wells lie within several miles of the Nikaitchuq development area. The Unocal East Harrison Bay State #1 well lies near the northwest corner of the KRU, to the southwest of the NU. The well was drilled in February 1977 to a measured depth of 9,809 feet, bottoming in argillite basement. The East Harrison Bay State #1 well logs appear to contain about 15 feet of oil-bearing Kuparuk sandstone that appears cemented in the upper half. The Jurassic section looks silty on logs. The ARCO Kalubik 3 well, drilled in February 1998, lies to the south-southwest of the Nikaitchuq area. The well bottomed in the Jurassic at a measured depth of 7,000 feet. The well encountered a 40-foot-thick MD interval of Kuparuk C sandstone that appears on electric logs as oil-bearing, but siderite cemented in the upper 10 feet of the interval. On well logs the Jurassic interval appears silty with a 12-foot silty sand developed around 6,565 feet MD. The well was plugged and abandoned on March 6, 1998.

3. Drilling History

The first major exploration activity in the area in the early 1970s targeted the Ivishak Formation following the discovery of the prolific Ivishak Formation in Prudhoe Bay State #1 in 1967. The Hamilton Brothers Milne Point #18-1 was one of the early wells drilled on the Milne Point structure in 1970 in search of Ivishak and Lisburne objectives. This well encountered about 50 feet of tight oil-saturated sandstone that was not tested and a section of Kuparuk sandstone that tested at a rate of 875 BOPD. This discovery led to increased industry interest in the Milne Point area and led to exploration and delineation drilling for Kuparuk reserves. In the early 1980s the Sag River was cored in the Conoco Milne Point Unit #C-1 well and contained bleeding oil and gas. The Sag River Sandstone was also cored in the MPU #L-1 well and contained no visible porosity or staining and the Sag River appeared tight on wire line logs.

In the early 1990s about a dozen wells were drilled to the west-southwest of the Nikaitchuq area with Jurassic sandstones and Kuparuk C sandstones as targets. The ARCO Kalubik #1 well encountered approximately 160 feet of productive Nuiqsut and Nechelik sandstone that tested at an unstimulated rate of 336 BOPD. In addition the well penetrated an 85-foot section of Sag River Sandstone with calculated log porosities in the range of 15 to 22 percent. The Thetis Island #1 well also encountered an 80-foot section of porous Sag River sandstone with log-calculated porosities in the range of 16-24 percent. A pay section of Nuiqsut sandstone was also encountered in this well that tested at an average rate of 120 BOPD with a high rate of 650 BOPD. Both the Kalubik #1 well

and Thetis Island #1 well drilled through Brookian sandstones that contained mud log hydrocarbon shows.

In the late 1990s BP drilled several dedicated Sag River Sandstone test wells, including MPU #C-23, #K-33, #E-13A, 3F-33, #F-33A, and #F-73A. Alaska Oil and Gas Conservation Commission (AOGCC) production data indicate that several Milne Point wells have produced oil out of the Sag River Sandstone and two oil producing wells MPU F-33A and K-33, are currently shut-in. MPU #C-23 produced 378,012 barrels of oil between 1996 and 2001. MPU #F-33 produced 314,276 barrels of oil between September 1996 and May 1999 and was subsequently plugged and abandoned. MPU #K-33 has produced approximately 93,241 barrels of oil since 1997. MPU #E-13A produced 366,665 barrels of oil between 1995 and April 2001. MPU #F-33A produced approximately 533,351 barrels of oil since April of 2001. MPU #F-73A produced 13,430 and is now a water alternating gas injection (WAGIN) well. AOGCC reservoir data indicate that the oil commonly recovered from the Sag River sandstone has an API oil gravity of about 37 degrees. Total production from the MPU Sag River Sandstone has been 1,709,268 barrels of oil and 1,754,912 MSCF gas through February 2006.

The original GOR ranged from 784 – 974 SCF/STB. Production from the Sag River pool at MPU has been intermittent with shut-in periods from June 1999 through February 2002 and all of 2006.

4. Certified Wells in the Vicinity

Eight wells southwest of the Nikaitchuq area have been certified by the state as capable of production in paying quantities: the Exxon Thetis Island #1, the Kalubik #1, the Kuukpik #3; and five Colville Delta wells (Texaco Colville #1, #1A, #2, and #3 and the Amerada Hess Corporation Colville 25-13-6). The two closest certified wells to the Nikaitchuq development area are the Exxon Thetis Island #1 and ARCO Kalubik #1. The Pioneer Ivik #1 well, drilled about three miles south of Thetis Island #1 well in 2003, tested 1,300 BOPD in Jurassic sands.

The Exxon Thetis Island #1 well was spud on March 6, 1993, and completed on April 28, 1993. A combined co-mingled drill stem test was conducted in two intervals: 6,356 – 6,364 feet MD in a thin Kuparuk C sandstone and 6,404 – 6,460 feet MD in a Jurassic (probably Nuiqsut) sandstone. During the first 24 hours of the well test the well stabilized on an 18/64” choke at a flow rate of 64 BWPD and 43 BOPD (rate varied between 50-350 BOPD) of 24.8-degree API oil. The well was then treated with acid and flowed for 30 hours. The well flow rate stabilized on an 18/64” choke at an average rate of 154 BOPD in the last four hours of the test (188 BOPD rate the last hour of the test). Exxon also tested a sandstone within the Seabee Formation at 5,576 – 5,633 feet MD that produced mud filtrate with a trace of oil. Exxon applied for Thetis Island Unit Well 1 certification for lease ADL 379301 on May 18, 1994. The Thetis Island well was certified as capable of production in paying quantities on February 24, 1995.

The ARCO Kalubik #1 was spud on March 5, 1992, and completed on May 1, 1992. A drill stem test was conducted on the Kalubik #1 between April 16-19, 1992, on a perforated interval of Kuparuk C sandstone from 6,085 – 6,120 feet MD. The interval was tested for a 24-hour flow period and produced at a rate of 1,200 BOPD with a 450 GOR and 0 percent water cut. Two other intervals were tested in the well. An upper Cretaceous sandstone (5,050 – 5,250 feet MD) recovered 4.5 BO and 146 BW in a 12.5-hour test from which an average oil rate of 10 BOPD was calculated. The Jurassic Nuiqsut sandstone at 6,385-6,445 feet MD was also tested and recovered 280 BO (with a measured API gravity of 23 and a GOR of 232 scf/stb) and no formation water. During the 20-hour test a measured oil rate of 336 BOPD was recorded. ARCO applied for well certification for the Kalubik 1 well on 9/8/1997 and the well was certified by the state for the Kuparuk C sandstone effective January 21, 1998.

Southwest of the Kalubik #1 well the Texaco Colville Delta #1, #2, and #3, and the Amerada Hess Corporation (AHC) Colville #25-13-6 1 wells were certified by the state as capable of production in paying quantities from the Jurassic Nuiqsut sandstone on 10/14/1991. In the Texaco Colville Delta #3 well a test was done on a Torok sandstone (5,120 – 5,183 feet MD) that recovered 841 BO (24-degree API gravity) and diesel, 2 BW, and 508 MCF in 95.75 hours. A Torok test in the Texaco Colville Delta #2 well was wet. The state certified the ARCO Kuukpik #3 well as capable of production in paying quantities for the Kuparuk C and Jurassic Nuiqsut sandstones on April 14, 1993.

5. Brookian Sandstone Potential

Brookian sandstones were deposited during latest Cretaceous and Paleocene time in available accommodation spaces as the Colville Trough was filled with sediment in response to thrust loading from the Brooks Range, a large north vergent fold and thrust belt to the south. Brookian sandstone at 5,050 – 5,250 feet in the Kalubik #1 well tested oil (API gravity not measured) at the rate of 10 BOPD. Brookian sands were also tested in the Thetis Island #1 well at depths of 5,576 – 5,578 feet MD and 5,631 – 5,633 feet MD that produced mud filtrate with a trace of oil.

6. Jurassic Sandstone Potential

Several wells in the Colville Delta area tested Nuiqsut sands: the Texaco Colville Delta #1 well produced at a rate of 1,075 BOPD of 25 API oil; the Texaco Colville Delta #2 well produced at a rate of 409 BOPD with the measured oil gravity varying from 24- to 40-degree API; the Texaco Colville Delta #3 well produced at a rate of 2,170 BOPD of 27.7-degree API oil; and the ARCO Kalubik #1 well produced at a rate of 410 BOPD of 21-degree gravity oil.

7. Sag River Formation Tests

KMG Nikaitchuq #1 (completed April 1, 2004)

Nikaitchuq #1 encountered 41 feet gross and 23 feet net pay in the Schrader Bluff OA sand and 33 feet gross and 17 feet net Sag River B Sand. The Schrader Bluff was not tested.

On April 19, 2004 KMG announced that the Nikaitchuq #1 well “production tested more than 960 BOPD of 38-degree API crude” from the Sag River Sandstone between the depth of 10,408 – 10,472 feet MD (8,679 – 8,741 feet subsea TVD). The Sag River sand was tested for 210 hours, fluids were produced for 150 hours after oil reached surface. Daily rate peaked at 960 BOPD on Day 3 and declined to 760 BOPD at the end of the Day 6. Daily rates were calculated on a 24-hour basis rather than using instantaneous rates as plotted in the operator’s report. GOR was 937 SCF/STB during the test. Wellhead pressure (WHP) fluctuated during the test mainly caused by water-loading and gas-slugging. The final WHP ranged between 300 psi to 400 psi and 14 percent water cut. A pressure transient test analysis showed permeability of about 3 – 4 millidarcies and no skin effect (undamaged). The 591-foot test radius of investigation represents about 25 acres, a relatively small portion of the reservoir.

KMG Nikaitchuq #2

The well encountered 30.5 feet gross Sag River sand and 7 feet net Schrader Bluff OA sand. There was no flow test conducted. The well was cored in the Sag River Sandstone and permeability measured 2 millidarcies indicating tight reservoir rock.

KMG Nikaitchuq #3

A 3,000-foot horizontal section was drilled with approximately 1,834 feet of net pay in the Sag River Sandstone. The Sag River was tested using a pump for 81 hours after oil surfaced. The initial rate declined from 1,327 BOPD at Day 1 to 760 BOPD (at 81 hours) of 32-degree API oil. Solution GOR averaged about 230 SCF/STB during the test. Wellhead pressure stabilized at 130 psi and pump intake pressure down hole finished at 1,230 psi prior to shut-in. Water cut ranged from 40-60 percent during the test but the water source was not determined conclusively. Pressure transient analysis indicated 5 millidarcies permeability, no skin damage, and the drainage area bounded by faults. Source of water production hampers the assessment of the formation’s productivity.

8. Schrader Bluff Formation Tests

KMG Nikaitchuq #4

Approximately 3,000 feet of gross horizontal Schrader Bluff formation was drilled in this well, with approximately 2,270 feet of net pay, from a 30foot TVD net pay thickness. A two-week production test was performed on the well using an electric submersible pump (ESP) to aid in producing the 16 – 17 API crude. The well tested at rates up to 1,200 barrels of oil per day during periods of the initial test. Permeability estimated from the test were greater than 350 millidarcies and was confirmed from the analysis of the tests conducted on a whole core obtained from the well.

KMG Tuvaag #1

The well was not tested. It penetrated 30 feet net pay Schrader Bluff OA Sand and 12 feet net Schrader Bluff N sand. There were no cores taken at Tuvaag. Schrader Bluff N sand was interpreted to be oil filled here and at Kigun #1 appeared unconsolidated with permeability estimated from 100-1000 millidarcies and porosity 25-35 percent.

KMG Kigun #1

The well was not tested. It penetrated 29 feet net pay Schrader Bluff OA sand and 30 feet net N sand. An MDT tool run sampled the Schrader Bluff OA fluids which were 18° API, GOR 59 SCF/STB and viscosity of 82 cp at 87 degree reservoir temperature. (Contamination of the samples with oil-based mud caused concern about the reliability of the sample estimates.) Schrader Bluff OA sand core data indicated 25 percent to 38 percent porosity and up to 1,000 millidarcies permeability in the sandstone intervals.

9. Analog Schrader Bluff Formation Performance

The MPU Schrader Bluff Pool (Figure 1), KRU West Sak pool (Figure 2) and Prudhoe Bay Unit (PBU) Polaris and Orion pools – Figure 3, represent Schrader Bluff Formation analog performance. Each of the pools was developed initially with vertical or slanted completions. More recently a number of horizontal lateral and multi-lateral wells have been completed in each of these pools. MPU and KRU Schrader Bluff wells show a distinct, lower rate performance than the newer developed Polaris and Orion pool wells. The later Schrader Bluff Formation developments are building on earlier techniques by going from vertical to horizontal and multilaterals wells. The horizontal and multilaterals should consistently outperform the older wells because more formation is exposed and the completions are more efficient.

The wells in each Schrader Bluff Formation pool exhibit early flush production for six to 12 months. The PBU Schrader Bluff completions show slightly higher initial rate profiles followed by relatively steep decline. The average MPU Schrader Bluff completion (heavy bright green points and line) declined from 1,200 bopd to 500 bopd at 12 to 40 months. KRU West Sak lateral completions performed similar to MPU Schrader Bluff.

KMG has stated its plan is to develop Nikaitchuq Schrader Bluff Formation with horizontal wells. KMG's prognosis of performance can be compared to the analogs by evaluating average Schrader Bluff well performance from initial completion to date. There is nearly five years of history for the various Schrader Bluff Formation wells. Orion appears to be more productive so far but the long-term performance has not been adequately defined. KMG appears to assume its development will improve on the previous KRU and MPU Schrader Bluff completions by using the latest technology, namely horizontal and or multilateral completions. KMG's cases align reasonably with the MPU Schrader Bluff and KRU West Sak and PBU Polaris average performance. PBU Orion performance is notably better than KMG's high case average rates.

10. Analog Sag River Formation Performance

The Sag River Formation has been developed on a stand alone basis at MPU. Well performance is depicted in Figure 4 for the five MPU Sag River completions. They consistently show initial flush production followed by steep decline within the first year to less than 50 percent of the initial rate. KMG's Sag River tests showed similar initial production rates and comparable if not more pronounced decline. At this time no obvious upside is evident based on analog performance and KMG's test results. Stimulation and perhaps innovative EOR techniques could improve recovery prospects in the Sag River Formation at Nikaitchuq.

11. The Pools Are Sufficiently Delineated

KMG has adequately delineated the Schrader Bluff Formation in the Nikaitchuq area. The company's drilling, testing, and evaluation programs appear to have highlighted the obvious risks and identified the possible upside by extending drilling and completion technology. The Nikaitchuq facility may be standalone and therefore is likely economically challenged more so than the KRU, MPU, and PBU Schrader Bluff developments. These pools had established infrastructures to provide the basis for development.

Sag River Formation has lighter oil than the Schrader Bluff; however, it is plagued with poor quality reservoir rock. The development potential is marginal at best unless there are significant advances in stimulation or EOR technology. Delineation of the Sag River Formation at Nikaitchuq has revealed nothing better than the analog at MPU.

Figure 1. MPU Schrader Bluff Formation lateral performance and average performance (heavy green).

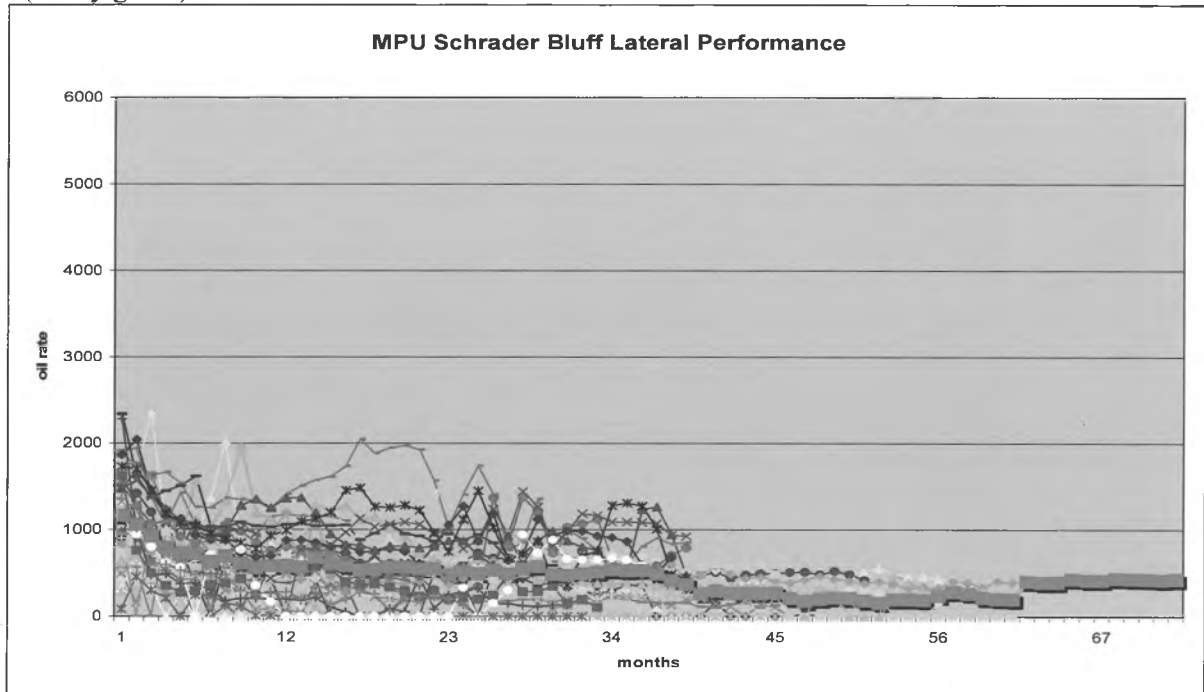


Figure 2. KRU West Sak sands lateral performance and average performance (heavy orange).

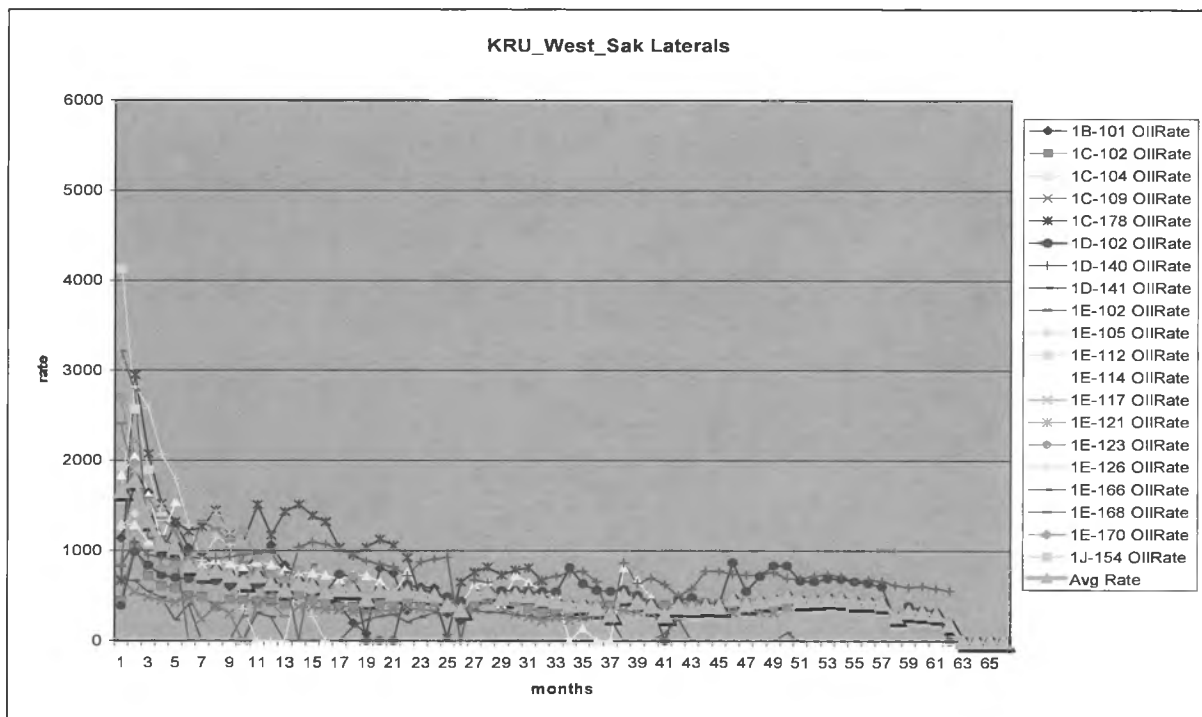


Figure 3. PBU Polaris and Orion Schrader Bluff Formation initial performance.

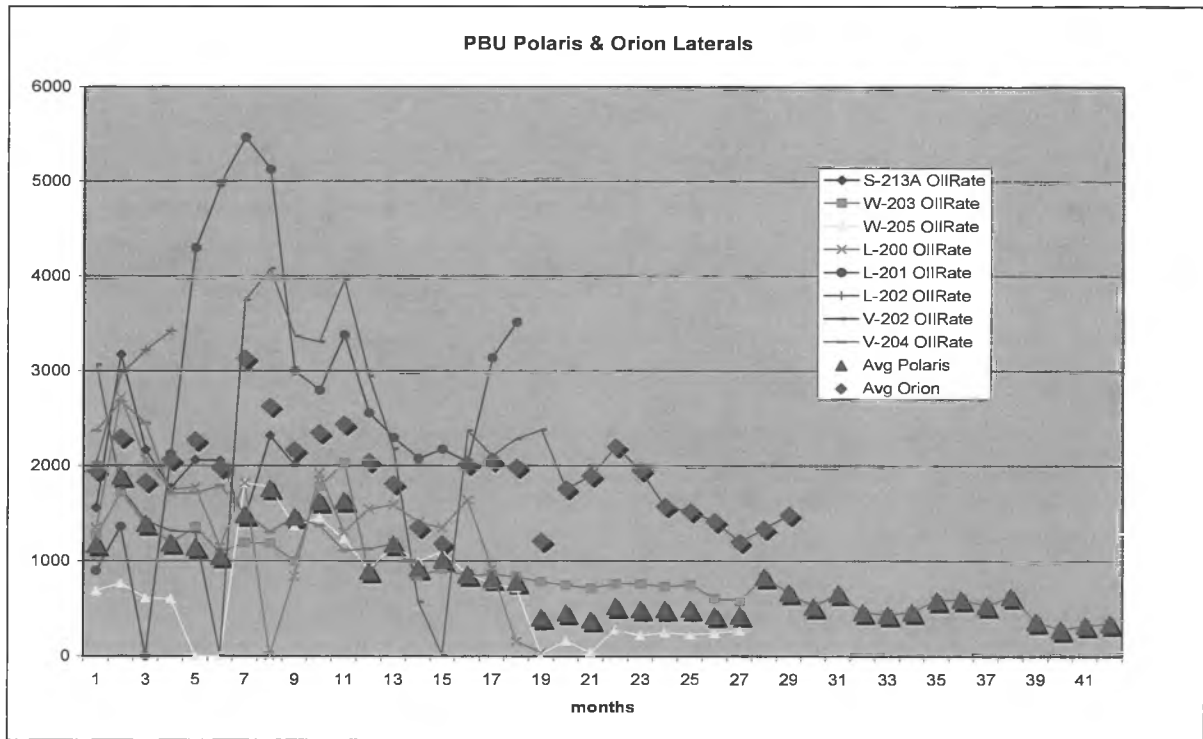
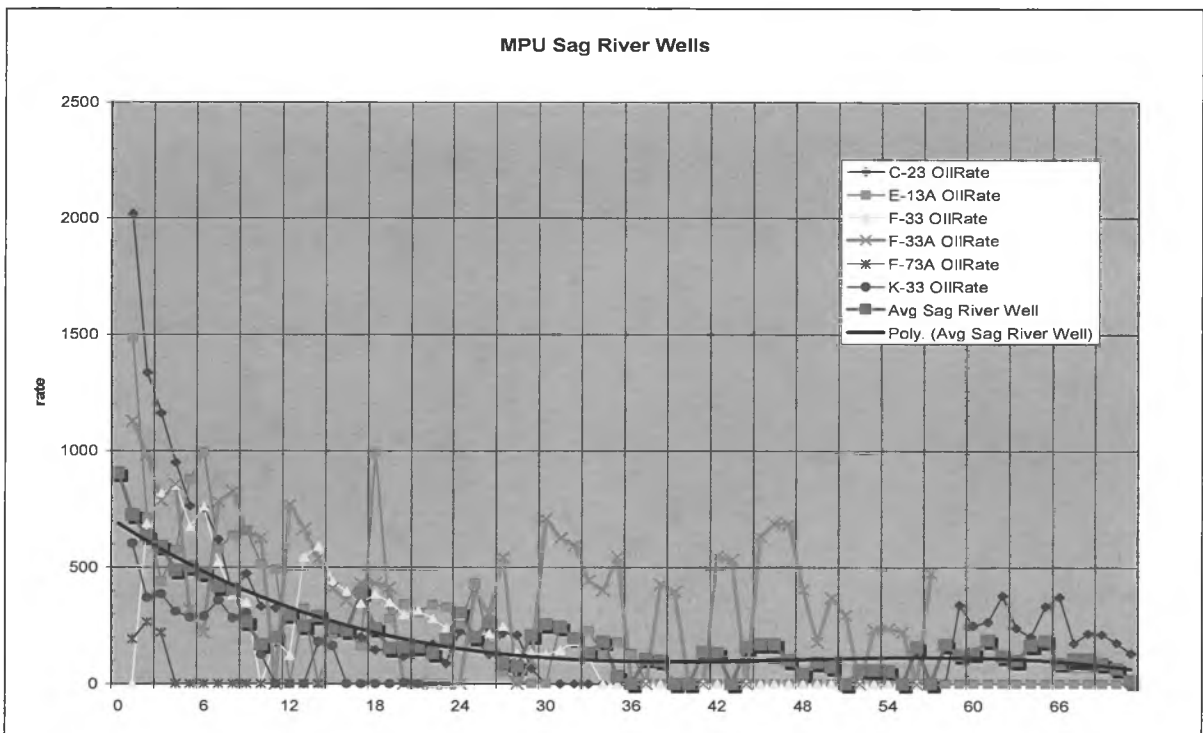


Figure 4. MPU Sag River Formation initial well performance.



C. The Pools Underlying The Leases Have Not Previously Produced Oil or Gas for Sale

No production of oil or gas for sale has occurred from these pools.

D. Oil Production Is Economically Feasible

KMG has submitted financial and technical data and analyses and requested that they be held confidential in accordance with AS 38.05.035(a)(9). Thus, this section does not discuss any confidential information concerning KMG's geologic, engineering and cost data. These documents are included and discussed in detail in the Confidential Economic Analysis and Internal Decision Process in Attachment 5.

To obtain royalty relief the applicant must show by clear and convincing evidence that without royalty modification the project is not economically feasible. The history of this area indicates little interest in area prospects with high exploration and development costs and low production estimates. These assessments were all made under much less beneficial fiscal assumptions which have since improved as discussed below.

E. Economic Analysis

~~DNR believes that~~ granting royalty modification should influence the behavior of the applicant – it should make a material difference to the applicant's decision-making. If, by modifying lease terms for the applicant, its behavior is not changed, i.e., working interest owners would have done the project anyway, the state has given up the value of the lost revenue for no reason. Because most companies are forward-looking in their decision-making process, DNR excludes sunk costs prior to the date of the application from the royalty modification analysis and the determination of whether a project is economically feasible. Sunk costs, or expenditures sanctioned prior to an application, do not factor into a project sanctioning decision for a forward-looking company and therefore should not be a factor in the determination of granting or denying royalty modification.

DNR analyzed the information submitted by KMG and used its own in-house economic model (DNR Model) for the Nikaitchuq development to independently assess the financial need and ultimate economic effects of a royalty modification for both KMG and the State of Alaska. KMG shared with the state portions of its proprietary economic model, but the state chose to use its own model that incorporated many input assumptions provided by KMG.

DNR examined the assumptions and methods currently in use by the U.S. Minerals Management Service (MMS) for the Deep Water Royalty Relief Program (DWRR). The MMS has developed an in-house proprietary probabilistic economic model for Royalty Suspension Viability Program (RSVP). Where possible, DNR adopted an approach

similar to that of the MMS by developing an independent model and implementing a decision path using economic metrics from the model.

An economic model reflects a particular view of a project's economics. The DNR Model describes the expected investment, production, price, revenue, and cost for the Nikaitchuq development over at least a 40-year time horizon. The DNR Model incorporates the state and federal tax and royalty fiscal system, as well as other important commercial relationships. This in-house model also was flexible, allowing DNR to quickly incorporate changes to the fiscal system and properly model the recently enacted production tax (PPT), signed into law on August 22, 2006. The model provides a platform for systematic evaluation of a change in the royalty rate in terms of various financial metrics for the project including annual and cumulative discounted and undiscounted cash flow, years to payout, net present value (NPV), expected monetary value (EMV), and internal rate of return (IRR) on investment, as well as state revenues. Also, DNR used its model to carry out sensitivity analysis of key driver assumptions and to characterize certain price, production, and cost variables in terms of probability distributions to evaluate how uncertainty among these drivers affects key project metrics and state revenues.

DNR incorporated the applicant's input data and probabilities into its model to derive independent results for the economic feasibility of the project. The DNR Model examines a range of possible inputs to derive a P50, or median, outcome from a Monte Carlo simulation. The P50 result is the value where 50 percent of the outcomes lay below this point and 50 percent of the outcomes lay above the P50 outcome. The DNR Model uses Palisades Software's "@Risk" Monte Carlo software application to run the simulations and generate charts, graphs and reports used in analysis.

For example, consider the determination of the amount of original oil in place (OOIP). The applicant submitted three scenarios (low, medium, and high) that characterize the range and likelihood of possible outcomes for the key determinants of OOIP: recovery rate, water saturation, permeability, porosity, net pay and areal extent. Each OOIP determinant is assigned a probabilistic value of perhaps P90, P50 and P10. The applicant's simulations indicate that 90 percent of the results are at least equal to X_{LOW} , in other words, the low case. A P50 indicates that 50 percent of the results are at least equal to X_{MEDIAN} , the median case. The P10 case is the high side case. Here the results fall at or above the X_{HIGH} range only 10 percent of the time. DNR's estimate of OOIP is calculated as a distribution of possible OOIP outcomes that takes into account the ranges and likelihoods for each of the OOIP determinants. The P50 OOIP calculated by the DNR Model directly incorporates uncertainty; it is risk weighted.

Calculating risk weighted outcomes is critical to a full analysis of a project. Once an OOIP distribution has been determined, an estimated ultimate recovery distribution and rate profile are determined based on the applicant's reservoir simulation results. The rate profile, when combined with netback price, determines the revenue stream. Annual netback prices were generated from an Ornstein-Uhlenbeck type Mean-Reversion price

model² with parameters estimated as described by Schwartz (1997)³ using annual price data for Alaska North Slope (ANS) West Coast crude as reported by Platt's. The price for 2006 was taken from U.S. Energy Information Agency's most recent price projection for West Texas Intermediate (WTI) crude, and adjusted for ANS-WTI basis by taking the previous 12-month average difference between these two prices. The riskweighted cost profiles are then matched to the revenue stream generated by the probabilistic price and production models. This yields an NPV distribution. The mean of the NPV distribution is the EMV for the entire project that incorporates uncertainty and can be compared "apples-to-apples" with other versions of the project.

Various what-if sensitivity analyses may be run by varying fiscal terms such as the tax system, interest rate, royalty rate and discount rate. For example, using the Excel goal seek function on discount rate, the DNR Model will calculate the discount rate at which the project reaches payout in 25 years. The DNR Model can assess outcomes for any level of probability, P1, P10, P99, for example, the state's share of divisible income under the P10 case, (high side).

The DNR and KMG models did not produce identical results. The numerous work sessions and presentations (Attachment 6) served to resolve some differences in modeling between DNR and KMG. And while the resulting DNR model reflects some disagreement between DNR and KMG on the model results, the differences can largely be explained by differences in the following formulas and assumptions:

1. severance tax formulas and input data assumptions;
2. oil price assumptions;
3. TAPS tariffs assumptions; and
4. oil quality adjustments assumptions.

DNR has received increasingly detailed input data from KMG at several points during the royalty modification application process. With each submission, KMG has revised the range of possible outcomes for resource, production, and cost. This reflects the increased level of knowledge that KMG has gained through study of the project and a more focused view of the project scope on the leases where the resources have been best delineated. DNR has used its model to analyze the series of submissions and has independently determined that the Nikaitchuq development, under the revised production tax, PPT, is economically feasible and does not require royalty modification.

The DNR has determined that under the PPT and over the life of the project, KMG would pay, on a discounted basis, about \$120 million less in taxes than under the previous fiscal regime. The high capital expenditures for the Nikaitchuq project serve to offset other statewide income streams and lower the overall tax obligation for the corporation. KMG and its parent, Anadarko Petroleum Corporation, will realize very large profits from Alaska production if oil prices stay at current high levels over the next several years.

*less
under
PPT*

² Dixit & Pindyck, 1994, http://www.puc-rio.br/marco.ind/sim_stoc_proc.html#mc-mrd

³ The Stochastic Behavior of Commodity Prices: Implications for Valuation and Hedging", Schwartz, E., Journal of Finance, 1997, Volume 52, issue 3, 923-973

Simultaneously, high capital expenditures at Nikaitchuq will be taking place, resulting in lower net income statewide, offsetting statewide income dollar for dollar and generating “qualified capex” credits that reduce tax obligations. Additionally, at high prices the progressive element of the PPT will be in effect, further increasing taxes for KMG. Capital investments in Nikaitchuq development offset income and result in a lower net tax liability to KMG.

Other impacts PPT will have on this project are shown in Table 1. From the working interest owner’s perspective, the new tax regime improves the NPV, IRR, and the profit to investment ratio for the Nikaitchuq development project. At the same time PPT is improving the economics for the working interest owners, the State of Alaska is giving up a significant amount of tax revenue for this project.

Table 1. Effect of severance tax change, implementing PPT, on project economics.

	With PPT - Without PPT Difference
NPV(12% discount rate)	\$86 MM
IRR	6.5%
Profit/Investment	17.7%
State of Alaska NPV(5)	-\$87 MM

Under AS 38.05.180(j)(7)(A)&(B), DNR has the option of contracting with an independent consultant to provide additional analysis of a royalty modification application. The value of the contract is limited to \$150,000.00, to be paid by the applicant. DNR did not contract with an outside consultant for the analysis of this application.

During DNR’s discussions with the applicant and analysis of its royalty modification application KMG expressed concern that if the commissioner denied royalty modification it might be precluded from applying for royalty modification at a later date based on new information. The royalty modification statute does not preclude a company that has previously applied for royalty modification from applying again.

V. DISCUSSION OF THE FINAL FINDINGS AND DETERMINATIONS

A. Royalty Modification Requirements

1. KMG’s application for royalty modification on ADLs 355021, 355024, 388571, 388572, 388574, 388575, 388577, 388578, 388580, 388581, 388582, 388583, 390615, 390616, meets the requirements for consideration under AS 38.05.180(j)(1). KMG paid the filing fee and submitted a complete application for the royalty modification, including financial and technical data that meet the requirements of 11 AAC 88.105, 11 AAC 83.185, 11 AAC 05.010(a)(10)(H), and AS 38.05.180(j)(6).

2. The Schrader Bluff and Sag River pools have been sufficiently delineated to the satisfaction of the commissioner for the purpose of considering royalty modification and these pools have not previously produced oil or gas for sale.
3. KMG has not shown that oil or gas production from the Schrader Bluff and Sag River pools would not otherwise be economically feasible.
4. KMG has failed to make a clear and convincing showing that a modification of royalty meets the requirements of 38.05.180(j) and is in the best interests of the state.

B. Royalty Modification Denied

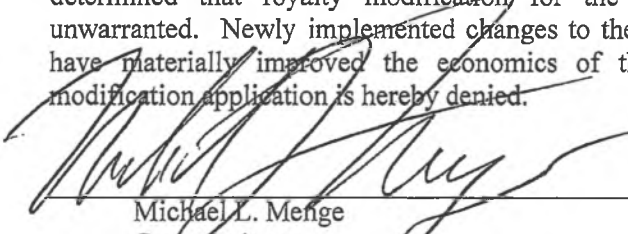
AS 38.05.180(j)(1)(A), under which the application considered here was made, authorizes the DNR commissioner to provide for royalty modification when, in part, oil or gas production from the field or pool would not otherwise be economically feasible. DNR concludes that KMG has failed to show by clear and convincing evidence that the Nikaitchuq development project is economically infeasible without royalty modification and that the modification is in the best interests of the state.

C. Summary of Public Comments

The only public comment received was from the applicant. DNR believes that all of the applicants concerns have been addressed during the detailed analysis and numerous discussions that have occurred throughout the process of evaluating this application.

VI. FINAL FINDINGS AND DETERMINATION

After consideration and analysis of the materials presented by the applicant and comments received regarding the preliminary finding and determination, the DNR has determined that royalty modification for the Nikaitchuq development project is unwarranted. Newly implemented changes to the tax structure for the State of Alaska have materially improved the economics of this project. Therefore, the royalty modification application is hereby denied.



Michael L. Menge
Commissioner

10/31/06

Date

cc: William Van Dyke, Director, Division of Oil and Gas
Kevin Banks, Senior Commercial Analyst, Division of Oil and Gas
Jeff Landry, Department of Law

VII. ATTACHMENTS

ATTACHMENT 1

Nikaitchuq Royalty Modification Application, Kerr McGee, January 11, 2006



KERR-McGEE OIL & GAS CORPORATION

1666 Northchase • Houston, TX 77053

DAVID HENKE
SENIOR INTERNATIONAL NEGOTIATOR

PHONE (281) 673-6337
FAX (281) 673-5245

January 11, 2006

The Honorable, Commissioner Michael Menge
Department of Natural Resources, State of Alaska
550 W. 7th Avenue, Suite 1400
Anchorage, AK 99501

**Re: Request for Royalty Modification
Various Leases
North Slope Alaska**

Dear Commissioner Menge,

Kerr-McGee Oil & Gas Corporation ("Kerr-McGee") has drilled 3 exploratory wells and 3 appraisal wells in the area depicted on Exhibit A attached hereto (hereinafter "Area"). It has conducted extensive reservoir evaluation, engineering studies, and economic analysis to determine if it is feasible to develop and produce the hydrocarbons discovered in the Schrader Bluff and Sag River formations. Kerr-McGee has, on a confidential basis, shared with various personnel within the Division of Oil and Gas reservoir data, the results of reservoir and engineering analysis, and economic studies related to the Area.

Kerr-McGee hereby requests Royalty Modification for the Alaska State leases described on Exhibit "B" attached hereto ("Subject Leases") pursuant to AS 38.05.180(j). This application is limited to production from the stratigraphic equivalent of the interval from 3,470' to 8,600' TVDSS on the Kigun #1 PB01 log. As to ADL 355021 it is further limited to those depths below the stratigraphic equivalent of 100' below 7,426' TVDSS as drilled in the Conoco NW Milne No. 1 Well. As to ADL 355024 this application is limited to that portion of the lease described on Exhibit B.

This application is submitted by Kerr-McGee on behalf of itself and co-lessee Eni Petroleum Exploration Co. Inc. ("ENI").

Kerr-McGee on behalf of itself and ENI respectfully requests your approval and authorization of the reduction of royalty from the amount set out on Exhibit B to a flat five percent.

A check in the amount of two hundred fifty dollars (\$250.00) is attached hereto in payment of the filing fee for this application.

Kerr-McGee has previously provided to personnel of the Division of Oil and Gas, on a confidential

basis, detailed geologic, engineering, and economic analysis sufficient to establish the following:

- 1 The oil field or pool underlying the Subject Leases has been sufficiently delineated.
- 2 The oil field or pool has not previously produced oil or gas for sale
- 3 Oil production from the field or pool would not otherwise be economically feasible.

A summary of the data previously submitted, together with related exhibits which we request you consider in making your determination is attached.

Kerr-McGee submits that it has made a clear and convincing showing through this application and the previously submitted confidential information that the proposed modification of royalty is in the best interest of the State of Alaska and meets the requirements of AS 38.05.180 (j).

Kerr-McGee requests that the information previously provided on a confidential basis remain confidential to the extent permitted by law and regulation and consistent with the requirements of this application and the related review process.

Yours truly,

David Henke

Note: Throughout this document click on the Exhibits and Figures with boxes and jump to the picture of that particular Exhibit or Figure. Click on the Figure number in the lower right hand corner and jump back to the text of the document.

EXHIBIT A TO THE MODIFICATION OF ROYALTY APPLICATION FILED BY
KERR-McGEE OIL & GAS CORPORATION ON JANUARY 11, 2006



EXHIBIT B TO THE MODIFICATION OF ROYALTY APPLICATION FILED BY KERR-McGEE OIL & GAS CORPORATION ON JANUARY 11, 2006

LEASE NUMBER	WORKING INTEREST OWNERS	WORKING INTEREST rounded	NET REV INTEREST rounded	LEASE EFFECTIVE DATE	ACRES	ROYALTY BURDEN
ADL 388581	Kerr-McGee	70.00%	56.0%	1/1/1998	2,500.00	16.66667%
		30.00%	24.0%			
ADL 388580	Kerr-McGee	70.00%	56.0%	1/1/1998	2,560.00	16.66667%
		30.00%	24.0%			
ADL 388583	Kerr-McGee	70.00%	56.0%	1/1/1998	1,894.00	16.66667%
		30.00%	24.0%			
ADL 388582	Kerr-McGee	70.00%	56.0%	1/1/1998	1,280.00	16.66667%
		30.00%	24.0%			
ADL355021 depth limited	Kerr-McGee	70.00%	57.75%	8/1/1983	5,120.00	12.5% + 30%NPS
		30.00%	24.75%			
			- 30%NPS			
ADL 390615	Kerr-McGee	70.00%	58.33%	7/1/2005	1,280.00	16.66667%
		30.00%	25.00%			
ADL 390616	Kerr-McGee	70.00%	58.33%	7/1/2005	1,280.00	16.66667%
		30.00%	25.00%			
ADL388571	Kerr-McGee	82.00%	64.85%	11/1/1998	2,766.36	16.66667%
		18.00%	14.24%			
ADL388572	Kerr-McGee	82.00%	64.85%	1/1/1998	1,968.24	16.66667%
		18.00%	14.24%			
ADL388574	Kerr-McGee	82.00%	64.85%	1/1/1998	1,920.00	16.66667%
		18.00%	14.24%			
ADL388575	Kerr-McGee	82.00%	64.85%	1/1/1998	2,560.00	16.66667%
		18.00%	14.24%			
ADL388577	Kerr-McGee	82.00%	64.85%	1/1/1998	1,280.00	16.66667%
		18.00%	14.24%			
ADL388578	Kerr-McGee	82.00%	64.85%	1/1/1998	1,280.00	16.66667%
		18.00%	14.24%			
Part of ADL 355024 as set out to the right	Kerr-McGee	54.80%	44.8%	6/1/1983	3,780.00	12.5% + 30% NPS
	ExxonMobil	44.84%	36.7%			
	T14N, R8E U Sections 24, 25, 36	0.36%	0.32%			
			T14N, R9E U Sections 19, 30, 31			

ATTACHMENT 2
Alaska Statute 38.05.180(j)

The commissioner

(1) may provide for modification of royalty on individual leases, leases unitized as described in (p) of this section, leases subject to an agreement described in (s) or (t) of this section, or interests unitized under AS 31.05

(A) to allow for production from an oil or gas field or pool if

(i) the oil or gas field or pool has been sufficiently delineated to the satisfaction of the commissioner;

(ii) the field or pool has not previously produced oil or gas for sale; and

(iii) oil or gas production from the field or pool would not otherwise be economically feasible;

(B) to prolong the economic life of an oil or gas field or pool as per barrel or barrel equivalent costs increase or as the price of oil or gas decreases, and the increase or decrease is sufficient to make future production no longer economically feasible; or

(C) to reestablish production of shut-in oil or gas that would not otherwise be economically feasible;

(2) may not grant a royalty modification unless the lessee or lessees requesting the change make a clear and convincing showing that a modification of royalty meets the requirements of this subsection and is in the best interests of the state;

(3) shall provide for an increase or decrease or other modification of the state's royalty share by a sliding scale royalty or other mechanism that shall be based on a change in the price of oil or gas and may also be based on other relevant factors such as a change in production rate, projected ultimate recovery, development costs, and operating costs;

(4) may not grant a royalty reduction for a field or pool

(A) under (1)(A) of this subsection if the royalty modification for the field or pool would establish a royalty rate of less than five percent in amount or value of the production removed or sold from a lease or leases covering the field or pool;

(B) under (1)(B) or (1)(C) of this subsection if the royalty modification for the field or pool would establish a royalty rate of less than three percent in amount or value of the production removed or sold from a lease or leases covering the field or pool;

(5) may not grant a royalty reduction under this subsection without including an explicit condition that the royalty reduction is not assignable without the prior written approval, which may not be unreasonably withheld, by the commissioner; the commissioner shall, in the preliminary and final findings and determinations, set out the conditions under which the royalty reduction may be assigned;

(6) shall require the lessee or lessees to submit, with the application for the royalty reduction, financial and technical data that demonstrate that the requirements of this subsection are met; the commissioner

(A) may require disclosure of only the financial and technical data related to development, production, and transportation of oil and gas or gas only from the field or pool that are reasonably available to the applicant; and

(B) shall keep the data confidential under AS 38.05.035 (a)(9) at the request of the lessee or lessees making application for the royalty reduction; the confidential data may be disclosed by the commissioner to legislators and to the legislative auditor and as directed by the chair or vice-chair of the Legislative Budget and Audit Committee to the director of the division of legislative finance, the permanent employees of their respective divisions who are responsible for evaluating a royalty reduction, and to agents or contractors of the legislative auditor or the legislative finance director who are engaged under contract to evaluate the royalty reduction, if they sign an appropriate confidentiality agreement;

(7) may

(A) require the lessee or lessees making application for the royalty reduction under (1)(A) of this subsection to pay for the services of an independent contractor, selected by the lessee or lessees from a list of qualified consultants compiled by the commissioner, to evaluate hydrocarbon development, production, transportation, and economics and to assist the commissioner in evaluating the application and financial and technical data; if, under this subparagraph, the commissioner requires payment for the services of an independent contractor, the total cost of the services to be paid for by the lessee or lessees may not exceed \$150,000 for each application, and the commissioner shall determine the relevant scope of the work to be performed by the contractor; selection of an independent contractor under this subparagraph is not subject to AS 36.30;

(B) with the mutual consent of the lessee or lessees making application for the royalty reduction under (1)(B) or (1)(C) of this subsection, request payment for the services of an independent contractor, selected from a list of qualified consultants to evaluate hydrocarbon development, production, transportation, and economics by the commissioner to assist the commissioner in evaluating the application and financial and technical data; if, under this subparagraph, the commissioner requires payment for the services of an independent contractor, the total cost of the services that may be paid for by the lessee or lessees may not exceed \$150,000 for each application, and the commissioner shall determine the relevant scope of the work to be performed by the

contractor; selection of an independent contractor under this subparagraph is not subject to AS 36.30;

(8) shall make and publish a preliminary findings and determination on the royalty reduction application, give reasonable public notice of the preliminary findings and determination, and invite public comment on the preliminary findings and determination during a 30-day period for receipt of public comment;

(9) shall offer to appear before the Legislative Budget and Audit Committee, on a day that is not earlier than 10 days and not later than 20 days after giving public notice under (8) of this subsection, to provide the committee a review of the commissioner's preliminary findings and determination on the royalty reduction application and administrative process; if the Legislative Budget and Audit Committee accepts the commissioner's offer, the committee shall give notice of the committee's meeting to all members of the legislature;

(10) shall make copies of the preliminary findings and determination available to

(A) the presiding officer of each house of the legislature;

(B) the chairs of the legislature's standing committees on resources; and

(C) the chairs of the legislature's special committees on oil and gas, if any;

(11) shall, within 30 days after the close of the public comment period under (8) of this subsection,

(A) prepare a summary of the public response to the commissioner's preliminary findings and determination;

(B) make a findings and determination; the commissioner's findings and determination prepared under this subparagraph regarding a royalty reduction is final and not appealable to the court;

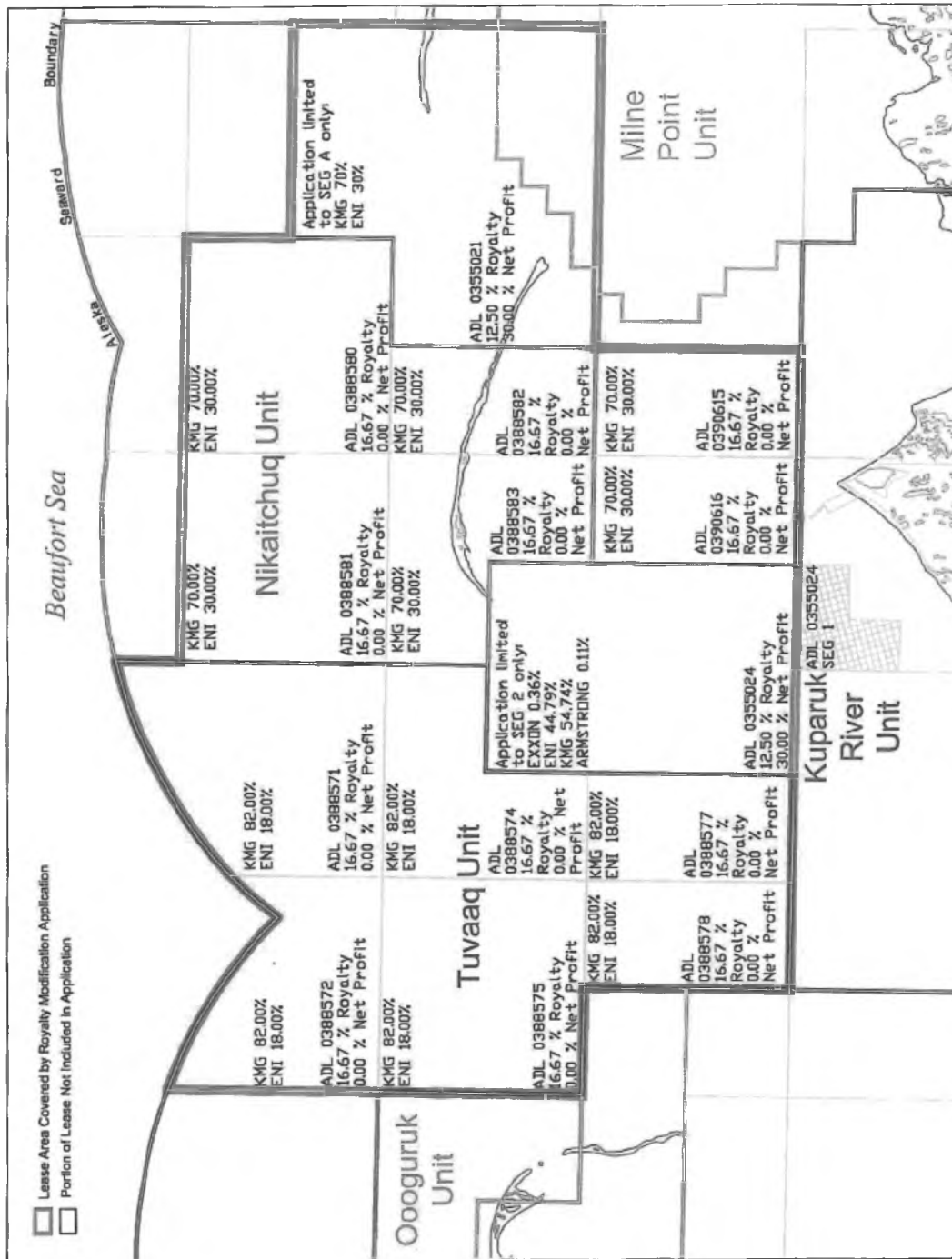
(C) transmit a copy of the findings and determination to the lessee;

(D) with the applicant's consent, amend the applicant's lease or unitization agreement consistent with the commissioner's final decision; and

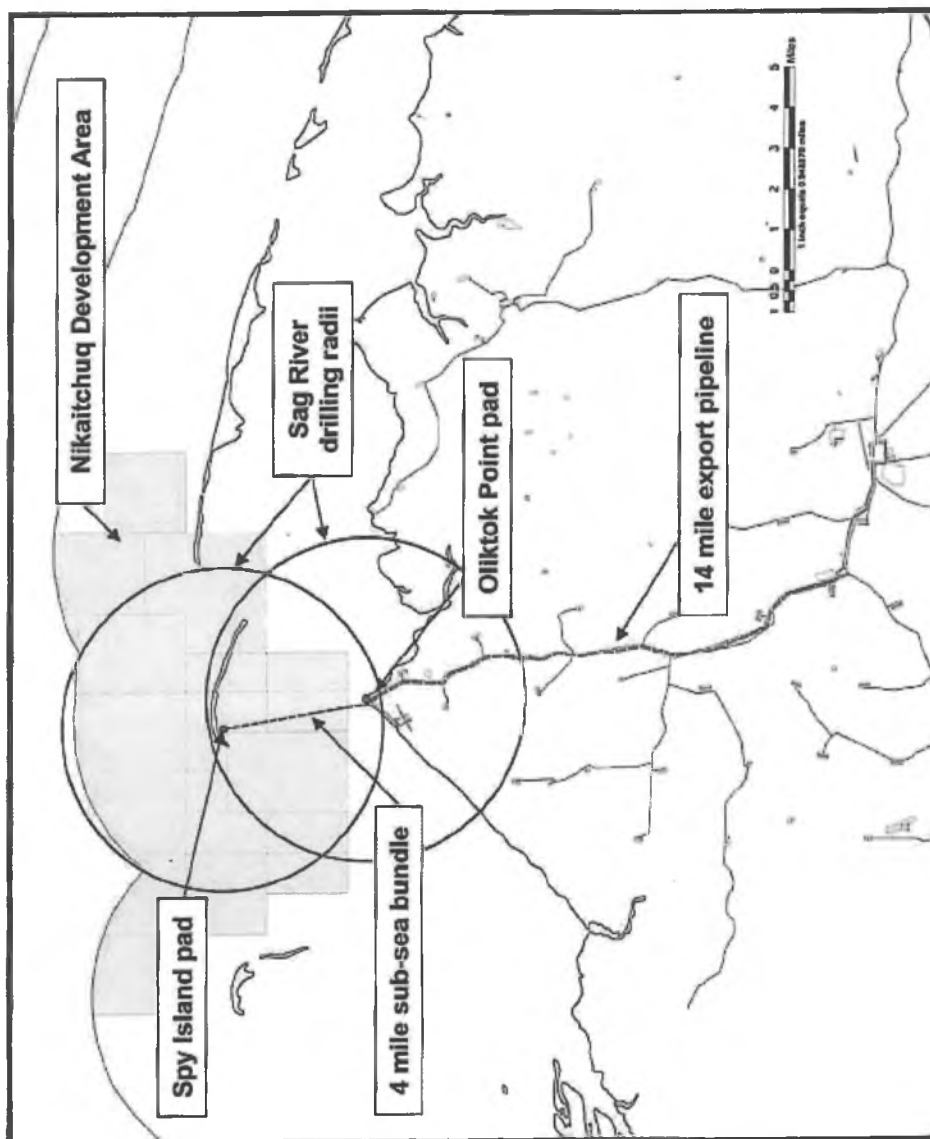
(E) make copies of the final findings and determination available to each person who submitted comment under (8) of this subsection and who has filed a request for the copies;

(12) is not limited by the provisions of AS 38.05.134 (3) or (f) of this section in the commissioner's determination under this subsection.

**ATTACHMENT 3
NIKAITCHUQ DEVELOPMENT AREA MAP**



**ATTACHMENT 4
NIKAITCHUQ PROJECT MAP**



ATTACHMENT 5
Confidential Economic Analysis and Internal Decision Process

**Nikaitchuq Development
Royalty Modification
Application**

**Findings and Determination of the Commissioner
of the Department of Natural Resources**

CONFIDENTIAL under AS 38.05.180(j) and “Deliberative Process Privilege”

Economic Analysis and Internal Decision Process

October ??, 2006

ATTACHMENT 6

Applicant Submittals and Work Sessions

Applicant Submittals:

August, 2005	Powerpoint presentation of G&G
January 11, 2006	Formal Application for Royalty Modification

Work Sessions and Presentations:

June 23, 2005	Nikaichuq Unit review
July 9, 2005,	Geology, Geophysics and Engineering
August 9, 2005	Reservoir Engineering Economics
September 27, 2005	Royalty Modification Pre-Application
November 3, 2005	Royalty Modification Pre-Application
November 9, 2005	Royalty Modification Pre-Application
January 11, 2006	Royalty Modification Application
February 9, 2006	Royalty Modification Application

ATTACHMENT 7

**Anchorage Daily News
Affidavit of Publication**

9/5/2006


1001 Northway Drive, Anchorage, AK 99508

AD#	DATE	TO	ACCOUNT	PRICE PER DAY	OTHER CHARGES	OTHER CHARGES #1	OTHER CHARGES #2	OTHER CHARGES #3	OTHER CHARGES #4	GRAND TOTAL
944037	09/01/2006	10G1674	ALAS1350	\$619.36						
				\$619.36	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$619.36

**STATE OF ALASKA
THIRD JUDICIAL DISTRICT**

Christine Clark, being first duly sworn on oath deposes and says that she is an advertising representative of the Anchorage Daily News, a daily newspaper.

That said newspaper has been approved by the Third Judicial Court, Anchorage, Alaska, and it now and has been published in the English language continually as a daily newspaper in Anchorage, Alaska, and it is now and during all said time was printed in an office maintained at the aforesaid place of publication of said newspaper. That the annexed is a copy of an advertisement as it was published in regular issues (and not in supplemental form) of said newspaper on the above dates and that such newspaper was regularly distributed to its subscribers during all of said period. That the full amount of the fee charged for the foregoing publication is not in excess of the rate charged private individuals.

Signed: 

Subscribed and sworn to me before this date:
September 6, 2006

Notary Public in and for the State of Alaska.
Third Division, Anchorage, Alaska

MY COMMISSION EXPIRES: 09/12/2007




**DEPARTMENT OF NATURAL RESOURCES
DIVISION OF OIL AND GAS**

August 29, 2006

**NOTICE
OF THE ISSUANCE OF THE
PRELIMINARY FINDINGS AND DETERMINATION
DENYING ROYALTY MODIFICATION ON
NIKAITCHUQ DEVELOPMENT LEASES:
ADLs 29615 and 29616 (NON-UNITIZED LEASES);
ADL 35502 (COMMITTED TO THE KUPARUK RIVER UNIT);
ADL 35504 (COMMITTED TO THE MILENE POINT UNIT);
ADLs 28857, 28852, 28854, 28853, 28851, and 28858
(COMMITTED TO THE TUVAAG UNIT);
AND
ADLs 28850, 28851, 28852, 28853, 28815, and 28816
(COMMITTED TO THE NIKAITCHUQ UNIT)**

The Alaska Department of Natural Resources (ADNR), Division of Oil and Gas (DO&G), gives notice under AS 38.05.180(1)(B) that it has issued the preliminary findings and determination under AS 38.05.180(1)(A) that denies the royalty modification request on the 14 leases: ADLs 25502, 28850, 28851, 28852, 28853, 28815, 28816, 28817, 28852, 28854, 28853, 28857, and 28858. DNR received a correctly filed initial application on January 11, 2006, from Kerr-McGee Oil & Gas Corporation (KMG) an operator of the Nikaitchue and Tuvaag units on behalf of itself and ENI Petroleum Exploration Co., Inc. (ENI).

To determine whether this royalty modification should be granted, the commissioner of ADNR is required to issue a final written finding and determination that the royalty modification applies to individual leases, leases unitized as described in AS 38.05.180(p), (s) or (t), or interests unitized under AS 31.05 to allow for production from an oil or gas field or pool if:

- 1) the oil or gas field or pool has been sufficiently delineated to the satisfaction of the Commissioner;
- 2) the field or pool has not previously produced oil or gas for sale; and
- 3) all or gas production from the field or pool would not otherwise be economically feasible;

ADNR has received and analyzed the applicant information regarding the development of these 14 leases. The analysis was then used to prepare this written preliminary finding and determination, which addresses the amended January 11, 2006, application. In this preliminary finding and determination the Commissioner establishes the scope of the administrative review for the denial of royalty modification and considers and discusses certain important facts and issues determined to be material as required by AS 38.05.180(1)(A) upon which the commissioner will base his final determination.

The commissioner shall publish this Preliminary Findings and Decision and give public notice of a 30-day public comment period as well as offer to appear before the Legislative Budget and Audit Committee and provide a review of the Findings and Determination and the administrative process. The commissioner shall keep the submitted data confidential under AS 38.05.03 (a)(9) at the request of the lessee or lessees making application for the royalty reduction. Within 30 days of the close of the public comment period the commissioner will prepare a summary of the public comments and make a Final Findings and Determination. The commissioner's final Findings and Determination regarding royalty modification is final and not appealable to the court.

PUBLIC COMMENT
DO&G invites the public to comment on any aspect of the royalty modification including the preliminary findings and determination and any proposed term or condition. Comments should be mailed, faxed or e-mailed to the Division of Oil and Gas, 558 W. 7th Ave., Suite 800, Anchorage, Alaska 99501-3460. Attention: Tim Ryward, Commercial Analyst, Department of Natural Resources, Division of Oil and Gas; Phone 907-269-4731, Fax 907-249-4938; e-mail Tim.Ryward@dnr.state.ak.us. Comments must be received no later than 5:00 p.m., October 2, 2006, to be considered in the final findings and determination.

Interested individuals may obtain copies of the preliminary finding and determination from DNR's website at www.dog.dnr.state.ak.us. The documents are also available for public review at the following locations: the Alaska State Library in Juneau, the Loussac Library in Anchorage, the DNR Public Information Center in Fairbanks, Anchorage, and the Borrow City Clerk's Office.

SUBJECT LEASE DESCRIPTION
The 14 subject leases are all located offshore in the Beaufort Sea north of Oliktok Point on Alaska's North Slope. Two of the subject leases are not committed to any oil and gas unit (ADLs 29615 and 29616) one lease is committed to the Kuparuk River Unit (ADL 35502); one lease is committed to the Milne Point Unit (ADL 35504); six leases are committed to the Tuvaag Unit (ADLs 28851, 28852, 28854, 28853, 28857, and 28858); and six leases are committed to the Nikaitchue Unit (ADLs 28850, 28851, 28852, 28853, 28815, and 28816). The amended application requests that the royalty rate for ADLs 35502 and 35504 be modified from a fixed royalty rate of 12.5 percent with a 30 percent NPS to the State to a 5 percent royalty rate with a 20 percent net profit share to the State, and that the royalty rate for ADLs 28851, 28850, 28853, 28852, 28815, 28816, 28851, 28852, 28854, 28853, 28857, and 28858 be modified from a fixed royalty rate of 16.667 percent to a fixed royalty rate of 5 percent.

MAPS
A map of the subject lease area is available on the division's website at www.dog.dnr.state.ak.us and in the Preliminary Findings and Determination document.

FINAL BEST INTEREST FINDING
DNR anticipates making the final findings and determination available to the public on or about October 9, 2006.

ALTERNATIVE COMMUNICATION FORMATS
This document complies with Title II of the Americans with Disabilities Act of 1990. This publication can be made available on CD or in alternative communication formats upon request. Please contact Brock Steiler at (907)275-8251 to make any necessary arrangements.

Date: August 29, 2006
/s/ Michael L. Menge Date
Commissioner

ADG 10-G-1674
Publish: September 1, 2006

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SOA/DEPT OF NATURAL
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550 W 7TH AVE, STE 800
ANCHORAGE, AK 99501

Date: September 14, 2006
CASE/PO: 10.G.1672
INVOICE : 906003575
PAPER: ARCTIC SOUNDER

AFFIDAVIT OF PUBLICATION

UNITED STATES OF AMERICA, STATE OF ALASKA, THIRD DIVISION.
BEFORE ME, THE UNDERSIGNED, A NOTARY PUBLIC THIS DAY
PERSONALLY APPEARED SHANNON MOONEY WHO, BEING FIRST DULY
SWORN, ACCORDING TO LAW, SAYS THAT SHE IS THE BILLING CLERK FOR:

THE ARCTIC SOUNDER.

PUBLISHED AT ANCHORAGE IN SAID DIVISION THREE AND STATE OF
ALASKA AND THAT THE ADVERTISEMENT, OF WHICH THE ANNEXED IS A
TRUE COPY, WAS PUBLISHED IN SAID PUBLICATION ON 9/7/2006 AND
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THEREON IS NOT IN EXCESS OF THE RATE CHARGED TO PRIVATE
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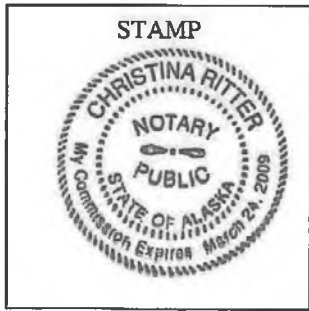
Shannon D. Mooney

SHANNON D. MOONEY
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SUBSCRIBED AND SWORN TO ME ON September 14, 2006

Christina Ritter

CHRISTINA RITTER
MY COMMISSION EXPIRES ON MARCH 24, 2009



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Community Support Services Coordinator
Hope Community Resources Inc. is recruiting for a Community Support Services Coordinator for our Juneau office. BA degree required with preference for Master's Degree in Health/Social Science, Special Ed or related fields, with an emphasis of study in mental health/developmental disabilities. A minimum of two year's work exp. in mental health/ human Services, at least one year of case management & supervisory experience. Must be able to work in a fast paced environment with a diverse caseload & coordinate effectively with other agencies, state personnel & program administrators. Experience with the Alaska Medicaid waiver program highly desirable. Previous training/ experience in mental health, family/individual counseling, group dynamics, & crisis interventions is preferred. Must be able to coordinate services, facilitate meetings, & provide support. To develop & implement behavioral plans. Strong oral & written communication skills are essential. Hope offers a competitive salary & excellent benefits. Please apply in person to Hope Community Resources Inc. 540 W. Airport Rd. (907) 561-5335 or 1-800-478-0078. Applications can be downloaded from our website at www.hopealaska.org. Hope is an EOE. (312185 9/7-2/8)

NOTICE OF APPRENTICESHIP OPPORTUNITY CONSTRUCTION DRIVER APPRENTICE

The Alaska Teamsters Construction/Maintenance/Pipeline Joint Apprenticeship and Training Committee will have application request forms at the Teamsters Training Center beginning September 1, 2006. Applications will then be sent at your request beginning the week of September 21, 2006. Apprenticeship applications will be accepted from September 28, 2006 thru October 10, 2006 and must be received at the Teamster Training Center 1048 Whitney Road Anchorage, AK 99501 (907) 278-3674 in person or mail by 4:30 PM October 10, 2006. Minimum qualifications: age 18 to apply, age 19 upon date of incanture, high school diploma or GED, must read US DOT drug, alcohol and medical requirements, must have an Alaska class "D" driver license for at least one year and provide a motor vehicle 10 year driving history report. The "Construction Driver Apprenticeship Program" requires four periods of 800 hours of on-the-job training (2000 hours total) and a minimum of 144

LEGAL NOTICES

Division of Retirement and Benefits, at P.O. Box 112023, Juneau, Alaska 99811-0203. Comments may also be submitted by e-mail sent to Anna_Kirsanova@admin.state.ak.us or by facsimile at (907) 465-3655. The comments must be received no later than 5:00 p.m. on September 30, 2006.

Oral or written comments may also be submitted at one of the following hearings:

September 27, 2006, in the 6th floor conference room of the State Office Building, 323 Willoughby Avenue, Juneau, Alaska. Hearing will be from 1 p.m. to 4 p.m.

September 28, 2006, in the 18th floor conference room of the Alwood Building, 550 W. 7th Avenue, Anchorage, Alaska. Hearing will be from 1 p.m. to 4 p.m.

Both hearings might be extended to accommodate those present before 3 p.m. who did not have the opportunity to comment. Those not able to attend in person may participate via teleconference by calling 1-800-315-6338 and using code 3597# when prompted.

If you are a person with a disability who needs a special accommodation in order to participate in this process, please contact Anna Kirsanova at 800-821-2251 or in Juneau at 465-3597 no later than September 18, 2006, to ensure that any necessary accommodations can be provided.

For a copy of the proposed regulation changes, contact Anna Kirsanova at 800-821-2251 or in Juneau at 465-3597, or go to www.state.ak.us/dbr.

After the public comment period ends, the Department of Administration will either adopt these or other provisions dealing with the same subject, without further notice, or decide to take no action on them. The language of the final regulations may be different from that of the proposed regulations. You should comment during the time allowed if your interests could be affected.

Statutory Authority: AS 14.25.003, AS 39.30.030; AS 39.35.005, AS 22.25.027, Former AS 39.37.090

Statutes Being Implemented, Interpreted, or Made Specific: AS 14.25, AS 22.25, AS 39.30, 060-39.30, 095, AS 39.35, former AS 39.37

Fiscal Information: It is estimated that the proposed regulation changes will require increased appropriations as follows: FY 07, \$464,000.00 - 1,221,000.00; FY 08, \$1,020,500.00 - 2,685,500.00; FY 09, \$1,122,500.00 - 2,954,000.00; FY 10, \$1,235,000.00 - 3,249,500.00

DATE: 8/31/2006
/s/ Traci Carpenter, Plan Administrator
(312217 9/7)

NOTICE OF THE ISSUANCE OF THE PRELIMINARY FINDINGS AND DETERMINATION DENYING ROYALTY MODIFICATION ON NIKAITCHUO DEVELOPMENT LEASES:

ADLs 390615 and 390616 (NON-UNITIZED LEASES):

ADL 355021 (COMMITTED TO THE KUPARUK RIVER UNIT);

ADL 355024 (COMMITTED TO THE MILNE POINT UNIT);

ADLs 388571, 388572, 388574, 388575, 388577, and 388578

(COMMITTED TO THE TUVAQAQ UNIT);

AND

ADLs 388580, 388581, 388582, 388583, 390615, and 390616

LEGAL NOTICES

(COMMITTED TO THE NIKAITCHUO UNIT)

The Alaska Department of Natural Resources (ADNR), Division of Oil and Gas (DO&G), gives notice under AS 38.05.180(j)(8) that it has issued the preliminary findings and determination under AS 38.05.180(j)(1)(A) that denies the royalty modification request on the 14 leases: ADL's 355021, 355024, 388580, 388581, 388583, 388582, 390615, 390616, 388571, 388572, 388574, 388575, 388577, and 388578. DNR received a correctly filed initial application on January 11, 2006, from Kern-McGee Oil & Gas Corporation (KMG) as operator of the Nikaitchuq and Tuvaqaq units on behalf of itself and ENI Petroleum Exploration Co. Inc. (ENI). To determine whether this royalty modification should be granted, the commissioner of ADNR is required to issue a final written finding and determination that the royalty modification applies to individual leases, leases unitized as described in AS 38.05.180(p), (s) or (t), or interests unitized under AS 31.05 to allow for production from an oil or gas field or pool if:

1. the oil or gas field or pool has been sufficiently delineated to the satisfaction of the Commissioner;
2. the field or pool has not previously produced oil or gas for sale; and
3. oil or gas production from the field or pool would not otherwise be economically feasible;

ADNR has received and analyzed the applicant information regarding the development of these 14 leases. The analysis was then used to prepare this written preliminary finding and determination, which addresses the amended January 11, 2006, application. In this preliminary findings and determination the Commissioner establishes the scope of the administrative review for the denial of royalty modification and considers and discusses certain important facts and issues determined to be material as required by AS 38.05.180(j)(1)(A) upon which the commissioner will base his final determination.

The commissioner shall publish his Preliminary Findings and Decision and give public notice of a 30-day public comment period as well as offer to appear before the Legislative Budget and Audit Committee and provide a review of the Findings and Determination and the administrative process. The commissioner shall keep the submitted data confidential under AS 38.05.035(a)(9) at the request of the lessee or lessees making application for the royalty reduction. Within 30 days of the close of the public comment period the commissioner will prepare a summary of the public comments and make a Final Findings and Determination. The commissioner's final Findings and Determination regarding royalty modification is final and not appealable to the court.

PUBLIC COMMENT

DO&G invites the public to comment on any aspect of the royalty modification including the preliminary findings and determination and any proposed term or condition. Comments should be mailed, faxed or e-mailed to the Division of Oil and Gas, 550 W. 7th Ave., Suite 800, Anchorage, Alaska 99501-3590, Attention: Tim Rhynd, Commercial Analyst, Department of Natural Resources, Division of Oil and Gas; Phone 907-268-8771, Fax 907-268-8936; e-mail Tim_Rhynd@dnr.state.ak.us. Comments must be received no later than 5:00 p.m., October 2, 2006, to be considered in the final findings and determination.

Interested individuals may obtain copies of the preliminary finding and determination from DNR's website at www.dog.dnr.state.ak.us. The documents are also available for public

LEGAL NOTICES

review at the following locations: the Alaska State Library in Juneau, the Loussac Library in Anchorage, the DNR Public Information Center in Fairbanks, Anchorage, and the Barrow City Clerk's Office.

SUBJECT LEASE DESCRIPTION

The 14 subject leases are all located offshore in the Beaufort Sea north of Orlitok Point in Alaska's North Slope. Two of the subject leases are not committed to any oil and gas unit (ADLs 390615 and 390616); one lease is committed to the Kuparuk River Unit (ADL 355021); one lease is committed to the Milne Point Unit (ADL 355024); six leases are committed to the Tuvaqaq Unit (ADLs 388571, 388572, 388574, 388575, 388577, and 388578); and six leases are committed to the Nikaitchuq Unit (ADLs 388580, 388581, 388582, 388583, 390615, and 390616). The amended application requests that the royalty rate for ADLs 355021 and 355024 be modified from a fixed royalty rate of 12.5 percent with a 30 percent NPS to the State to a 5 percent royalty rate with a 30 percent net profit share to the State, and that the royalty rate for ADLs 388581, 388580, 388583, 388582, 390615, 390616, 388571, 388572, 388574, 388575, 388577, and 388578 be modified from a fixed royalty rate of 16.8667 percent to a fixed royalty rate of 5 percent.

MAPS

A map of the subject lease area is available on the division's website at www.dog.dnr.state.ak.us and in the Preliminary Findings and Determination document.

FINAL BEST INTEREST FINDING

DNR anticipates making the final findings and determination available to the public on or about October 9, 2006.

ALTERNATIVE COMMUNICATION FORMATS

The ADNR, DO&G complies with Title II of the Americans with Disabilities Act of 1990. This publication can be made available on CD or in alternative communication formats upon request. Please contact Brock Stollary at (907)375-8251 to make any necessary arrangements.

Michael L. George

Commissioner

Published: 9/7

(312211 9/7)

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FOURTH DISTRICT

Before me, the undersigned, a notary public, this day personally appeared Katy Gallages, who, being first duly sworn, according to law, says that he/she is an Advertising Clerk of the Fairbanks Daily News-Miner, a newspaper (i) published in newspaper format, (ii) distributed daily more than 50 weeks per year, (iii) with a total circulation of more than 500 and more than 10% of the population of the Fourth Judicial District, (iv) holding a second class mailing permit from the United States Postal Service, (v) not published primarily to distribute advertising, and (vi) not intended for a particular professional or occupational group. The advertisement which is attached is a true copy of the advertisement published in said paper on the following day(s):

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136399 NOTICE OF THE ISS
and that the rate charged thereon is not excess of the rate charged private individuals, with the usual discounts.

Katy Gallages

Subscribed and sworn to before me on this 30 day
of SEPTEMBER, 2006

Shane Sankle
Notary Public in and for the State of Alaska.

My commission expires August 26, 2009

136399
NOTICE OF THE
ISSUANCE OF THE
PRELIMINARY FINDINGS AND DETERMINATION DENYING ROYALTY MODIFICATION ON NIKAITCHUQ DEVELOPMENT LEASES:
ADLA 380615 & 380616 (NON-UNITIZED LEASES)
ADL 355021 (COMMITTED TO THE KUPARUK RIVER UNIT); ADL 355024 (COMMITTED TO THE MILNE POINT UNIT); ADL 388571, 388572, 388574, 388576, 388577, and 388578 (COMMITTED TO THE TOVAAG UNIT); AND ADL 388580, 388581, 388583, 380615, and 380616 (COMMITTED TO THE NIKAITCHUQ UNIT)

The Alaska Department of Natural Resources (DNR), Division of Oil and Gas (DO&G), gives notice under AS 05.180(d) that it has issued its preliminary findings and determination under AS 05.180(d)(1) that it denies the royalty modification requests on 14 leases: ADL's 355024, 388580, 388581, 388583, 388582, 388583, 380615, 388571, 388572, 388574, 388575, 388577, and 388578. DNR received a correctly filed final application on January 11, 2006, from KenCo Oil & Gas Corporation (KMG) as operator of the Nikaitchuk and Tovaag units on behalf of ENI Petroleum Corporation Co. Inc. (ENI),

ADNR has received and analyzed the applicant information regarding the development of these 14 leases. The analysis was then used to prepare this written preliminary finding and determination. The Commissioner establishes the scope of the administrative review for the denial of royalty modification and considers and discusses certain important facts and issues determined to be material as required by AS 05.180(d)(1)(A) upon which the commissioner will base his final determination. The commissioner shall publish this Preliminary Findings and Decision and give public notice of a 30-day public comment period as well as offer to appear before the Legislative Budget and Audit Committee and provide a review of the Findings and Decision and the administrative process. The Commissioner shall keep the submitted data confidential under AS 05.035(a)(9) at the request of the lessee or lessees making application for the royalty reduction. Within 30 days of the close of the public comment period the commissioner will prepare a summary of the public comments and make a Final Findings and Determination. The commissioner's final Findings and Determination regarding royalty modification is final and not appealable to the court.

determine whether this royalty modification could be granted, the commissioner of ADNR is authorized to issue a final finding and determination that the royalty modification applies to individual leases, leases held as described in 05.180(p), (q) or (r), interests unitized under 05.180 to allow for production from oil or gas or pool if the oil gas field or pool has been sufficiently tested to the satisfaction of the Commissioner, the field or pool has previously produced oil or gas for sale, and oil or gas production in the field or pool would not otherwise be economically feasible.

PUBLIC COMMENT
DO&G invites the public to comment on any aspect of the royalty modification including the preliminary findings and determination and any proposed term or condition. Comments should be mailed, faxed or e-mailed to the Division of Oil and Gas, 850 W. 7th Ave., Suite 800, Anchorage, Alaska 99501-3580. Attention: Tim Ryland, Commercial Analyst, Department of Natural Resources, Division of Oil and Gas; Phone 507-268-8771, Fax 907-268-9338, e-mail: Tim.Ryland@dnr.state.ak.us. Comments must be received no later than 5:00p, October 2, 2006, to be considered in the final findings and determination. Interested individuals may obtain copies of the preliminary finding and determination from DNR's website, at www.dnr.state.ak.us. The documents are also available for public review at the following locations: the Alaska State Library in Juneau, the Loussac Library in Anchorage, the DNR Public Information Center in Fairbanks, Anchorage, and the Barrow City Clerk's Office.

SUBJECT LEASE DESCRIPTION
The 14 subject leases are all located offshore in the Beaufort Sea north of Oilfield Point on Alaska's North Slope. Two of the subject leases are not committed to any oil and gas unit (ADL 380615 and 380616); one lease is committed to the Kuparuk River Unit (ADL 355021); one lease is committed to the Milne Point Unit (ADL 355024); six leases are committed to the Tovaag Unit (ADL 388571, 388572, 388574, 388575, 388577, and 388578); and six leases are committed to the Nikaitchuk Unit (ADL 388580, 388581, 388582, 388583, 380615, and 380616). The amended application requests that the royalty rate for ADL 355021 and 355024 be modified from fixed royalty rate of 12.5 percent with a 30 percent NPS to the State to a 5 percent royalty rate with a 20 percent net profit share to the State, and that the royalty rate for ADL 388581, 388580, 388582, 388583, 380615, 380616, 388571, 388582, 388574, 388575, 388577, and 388578 be modified from a fixed royalty rate of 5 percent.

MAPS
A map of the subject lease area is available to the public on or about October 9, 2006.
ALTERNATIVE COMMUNICATION FORMATS
The ADNR, DO&G complies with Title II of the Americans with Disabilities Act of 1990. This publication can be made available on CD or in alternative communication format upon request. Please Contact Brock Steiner at (907) 375-8251 to make any necessary arrangements.
/s/By: Michael L. Menge
Publish: September 2,



ATTACHMENT 8
Public Comments

DNR received public comment from the following persons.

Mr. David Henke (via email)
Senior International Negotiator
Anadarko Petroleum Corp.
16666 Northchase
Houston, Texas 77060

Tim J. Ryherd

From: Henke, David
Sent: Monday, October 02, 2006 11:22 AM
To: tim_ryherd@dnr.state.ak.us
Cc: david.lawler
Subject: Comments re Preliminary Findings.... - Royalty Modification - Nikaitchuq area

Both Kerr-McGee Oil & Gas Corporation and Eni Petroleum US LLC have reviewed the Preliminary Findings and Determination for the requested royalty modification for the various leases in the Nikaitchuq area. We have each made individual determinations of the projected effect of the PPT legislation. We have also attempted to match the analysis completed by the DNR staff. Thus far we have not been successful in matching the results obtained by the DNR staff.

We believe it is premature to deny the application at this time for the following reasons:

1. We believe a full and open discussion between the staff and representatives of both Kerr-McGee and Eni identifying the parameters used for the calculation of the expected PPT results should be completed before a final decision is issued. Both Kerr-McGee and Eni will be ready to participate in such discussions during the first half of October. The analysis used in and following such discussions should be considered in the final determination process.

2. The Preliminary Findings and Determination were based upon the impact of recent changes in tax provisions but did not include an evaluation of ongoing changes in project economics or the currently estimated first production date. The costs for the Nikaitchuq project continue to increase and the costs in place after the completion of the 2-well program described below should be a more accurate estimate of the actual costs of the project at the point in time when a decision to proceed with sanction will be made. We believe a full analysis of the information available after the completion of the 2-well program will justify royalty modification.

3. We are conducting a 2-well program to gather additional information before making our final decision on sanctioning the project. The results, including costs, of this 2-well program should be utilized in making the final determination on royalty modification.

Please note my E-Mail Address has changed. Please update your contact list

Final Findings and Determination

For

**Nikaitchuq Development
Royalty Modification
Application**

Commissioner of the Department of Natural Resources

**APPROVAL
OF MODIFICATION OF ROYALTY
FOR LEASES:**

**ADLs 388571, 388572, 388574, 388575, 388577, 388581, 388582, 388583,
390615, 390616 and 391283**

January 11, 2008

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8. Public Comments

I. INTRODUCTION AND BACKGROUND

A. Introduction

On October 16, 2007, Eni US Operating Co. Inc. (Eni), as operator of the Nikaitchuq Unit (NU), on behalf of its affiliate Eni Petroleum US LLC, 100 percent working interest owner of the subject leases, submitted an application to the commissioner of the State of Alaska Department of Natural Resources (ADNR) for modification of royalty under AS 38.05.180(j)(1)(A) (Attachment 1). On November 30, 2007, ADNR issued a Preliminary Findings and Determination to respond to Eni's royalty modification application. The public was invited to comment on the preliminary decision for 30 days ending January 7, 2008. ADNR hereby issues its Final Findings and Determination as required under AS 38.05.

Eni has applied for royalty modification on 12 leases which overlie the Schrader Bluff and the Sag River reservoirs. However, the Sag River reservoir was withdrawn from the application at the request of Eni. Eni requests that the fixed royalty rates of

- 12.5 percent on the Net Profit Share (NPS) lease, ADL 391283, and
- 16.66667 percent on the 11 leases (ADLs 388571, 388572, 388574, 388575, 388577, 388580, 388581, 388582, 388583, 390615, and 390616)

be reduced to the minimum rate allowed, 5.0 percent, with an annual sliding-scale royalty percentage adjustment based on the level of Alaska North Slope West Coast (ANSWC) crude oil price. The 30 percent net profit share rate on ADL 391283 is to remain unchanged. Attachment 2 depicts the Nikaitchuq Unit boundaries and leases subject to this royalty modification application.

This Final Findings and Determination responds to the royalty modification application as required under AS 38.05.180(j)(8). Part I summarizes the royalty modification application and process. Part II reviews the history of the Nikaitchuq Unit formation and development, and Eni's royalty modification application. Part III reviews the state's authority to carry out royalty modification. Part IV reviews the requirements and terms of royalty modification pursuant to this application. Part V contains ADNR's analysis of the application under the royalty modification criteria. Part VI is the Final Findings and Determination.

B. Royalty Modification Procedure

This Final Findings and Determination is the first step in a process contemplated in AS 38.05.180(j) that could result in an authorization to modify the royalty terms for certain leases. The commissioner published the Preliminary Findings and Determination, gave public notice of a 30-day public comment period (Attachments 3 and 4), and offered to appear before the Legislative Budget and Audit Committee to provide a review of the

Findings and Determination and the administrative process. The commissioner will keep the submitted data confidential under AS 38.05.035(a)(9) at the request of the lessee or lessees making application for the royalty reduction. This Final Findings and Determination by ADNR regarding royalty modification is final and not appealable. With the Applicant's concurrence, ADNR will amend the subject leases to conform to the terms of this royalty modification Final Findings and Determination.

II. SUMMARY OF ENI'S APPLICATION FOR ROYALTY MODIFICATION

A. Unit and Lease Summary

ADNR approved the formation of the Nikaitchuq Unit effective April 29, 2004. At that time, Kerr-McGee Oil & Gas Corp. (KMG) held 70 percent of the working interest and Armstrong Oil & Gas Inc. (Armstrong) held 30 percent. The unit originally consisted of eight leases covering 12,968 offshore acres in the shallow waters of Harrison Bay in the Beaufort Sea, approximately three miles north of Oliktok Point. The Kuparuk River Unit (KRU) lies to the south, and the Milne Point Unit (MPU) lies to the east of the Nikaitchuq Unit. The Tuvaaq Unit, formed in August 2004, was adjacent to the western boundary of the original Nikaitchuq Unit. Effective October 5, 2007, ADNR approved the first expansion of the Nikaitchuq Unit, termination of the Tuvaaq Unit and the contraction of the Kuparuk River Unit. The Nikaitchuq Unit expanded to include all of the Tuvaaq Unit leases, the Kigun lease, formerly committed to the KRU, and two additional leases acquired by ENI at the 2004 Beaufort Sea Sale.

All 12 leases in the Eni royalty modification application are committed to the expanded Nikaitchuq Unit. (See lease map in Attachment 2.)

The ownership of the Nikaitchuq Unit has changed significantly since formation. Eni acquired Armstrong's 30 percent WIO of Nikaitchuq Unit in August 2005. In August 2006, Anadarko Petroleum Co. (Anadarko) acquired KMG, including KMG's 70 percent WIO in Nikaitchuq Unit, and became Nikaitchuq Unit operator. Eni subsequently acquired the remaining 70 percent Nikaitchuq Unit ownership from the operator, Anadarko, in March 2007, and became the 100 percent WIO and operator of Nikaitchuq Unit.

On January 11, 2006, KMG submitted an application for royalty modification under AS 38.05.180(j)(1)(A) for 14 leases of which 12 are the subject of this application.¹ KMG's application requested that the royalty rate for the 14 leases be modified from their respective existing fixed royalty rates of 16.67 percent and 12.5 percent to a fixed royalty rate of 5 percent. Effective October 31, 2006, the ADNR issued the Final Findings and Determination of the Commissioner of the Department of Natural Resources for the Nikaitchuq Development Royalty Modification Application denying KMG's application for royalty modification.

¹ The KMG application included ADLs 355021, 355024, 388571, 388572, 388574, 388575, 388577, 388578, 388580, 388581, 388582, 388583, 390615, and 390616.

B. Project Development History

In the 2003-2004 and 2004-2005 exploration/appraisal drilling programs KMG/Armstrong encountered accumulations of hydrocarbons in the area of the then-proposed Nikaitchuq Unit. A total of six wells were drilled in the Nikaitchuq area in the 2004 and 2005 winter drilling seasons; two additional wells were drilled in 2006.

The planned development includes:

- Construction of a gravel pad with drilling, gathering and production facilities on Oliktok Point near the existing ConocoPhillips Alaska Inc. seawater treatment facility.
- Construction of a gravel drilling island near Spy Island tied back via a 3.8-mile subsea flow line and utility bundle to Oliktok Point for fluid processing.
- Construction of a +/-14-mile pipeline from Oliktok Point to a tie-in near KRU DS-1Y pad for connection to the Kuparuk Transportation common carrier pipeline.
- Consideration of future modifications required to adjust facility configuration to accommodate actual results of well performance.
- A total of 73 wells drilled between 2008 and 2011, of which 31 are expected to be producers.
- First oil expected in 2010.

Development studies indicate that extended reach horizontal producing and injection wells required for pressure maintenance are needed to economically recover the hydrocarbons in place. The planned development would permit a relatively small "footprint" for centralized facilities and minimal well pads, thereby reducing environmental impacts to the region. Initial drilling will be from a 313,000-square-foot pad to be constructed at Oliktok Point. Existing roads will be utilized for access. The production facilities will be located on the same pad. Later, a small gravel island is to be constructed within the barrier islands for future drilling. A subsea bundle containing a three-phase production line and multiple utility lines will be constructed to connect the gravel island to Oliktok Point to transport production and provide fuel, secondary recovery fluid, and power to the gravel island.

C. Eni Royalty Modification Request

On October 16, 2007, Eni submitted an application (Attachment 3) to the ADNR commissioner for modification of royalty on 12 leases, ADLs: 388571, 388572, 388574, 388575, 388577, 388580, 388581, 388582, 388583, 390615, and 390616 and ADL 391283 under AS 38.05.180(j)(1)(A). In accordance with 11 AAC 88.105, 11 AAC 83.185, and 11 AAC 05.010(a)(10)(H) Eni submitted a complete application with the required \$250.00 filing fee.

The Eni application for royalty modification submitted on October 16, 2007, requests a 5.0 percent fixed royalty if the Alaska North Slope West Coast (ANSWC) crude oil price falls below an ANSWC price equivalent to the U.S. Department of Interior, Minerals Management Service (MMS) NYMEX West Texas Intermediate (WTI) oil price threshold for royalty modification for OCS August 2004-2006 deepwater oil leases in the Gulf of Mexico (GOM).² Eni proposes a sliding-scale royalty rate in any month after production start-up (expected in 2010) that would range between 5.0 and 16.6667 percent, depending on the average monthly price of ANSWC crude oil. An ANSWC monthly (nominal) price below the Alaska Department of Revenue (ADOR) *Spring 2007 Revenue Sources* forecast between 2010 (the year of first production) and 2017 shown in Figure II.1 (below) would trigger a reduced royalty rate from original fixed lease rates of 12.5 percent and 16.6667 percent, respectively. The amount of the reduction in royalty percentage would depend on (a) the original lease rate (either 12.5 percent or 16.6667 percent) and (b) the extent to which the actual future oil price falls below the ADOR forecast threshold.³

The original fixed royalty rate of 16.6667 percent for ADLs 388571, 388572, 388574, 388575, 388577, 388581, 388582, 388583, 390615, and 390616 and 12.5 percent with 30 percent net profit for ADL 391283 would be subject to the sliding scale modification in a low commodity price environment to a level at or above a floor of 5 percent. The 30 percent net profit share to the State attached to ADL 391283 would be unchanged under the Eni royalty modification proposal.

The Eni application also would provide full royalty relief at a reduced rate of 5 percent for all leases regardless of oil price if monthly production is below 4,000 barrels of oil per day for the first 10 years following the effective date of the royalty modification decision.

² ADNR estimates threshold to be \$42.53 per barrel in 2010 based on a 2007 NYMEX WTI price of \$42.64 assuming a 94 percent basis adjustment to ANSWC and 2 percent price escalation pursuant to the ENI proposal. See: MMS, *Price Thresholds and Annual Market Prices for MMS Deepwater and Deep Depth Oil and Gas Royalty Relief Programs*, Deep Water Oil, Economics Division at www.mms.gov/econ/DWRRAPrice1.htm.

³ Under the Eni proposal, the royalty percentage rate adjustment would be approximately $\frac{3}{4}$ percentage point per \$1 change in ANSWC price for leases with a 16.6667 percent base royalty rate and $\frac{1}{2}$ percentage point per \$1 change in ANSWC price for leases with a 12.5 percent base royalty rate. After 2017, the ADOR ANSWC price forecast is inflated by the monthly change in the Producer Price Index (PPI).

**III. SUMMARY OF ROYALTY MODIFICATION AUTHORITY
AS 38.05.180(j)(1)(A), (2), (3), (4)(A), (5)**

A. General Royalty Modification Requirements

AS 38.05.180(j)(1)(A) authorizes the DNR commissioner to provide for royalty modification on individual leases, leases unitized as described in (p) of this section (AS 38.05.180), leases subject to an agreement described in (s) or (t) of this section (AS 38.05.180), or interests unitized under AS 31.05 to allow for production from an oil or gas field or pool if:

1. the oil or gas field or pool has been sufficiently delineated to the satisfaction of the commissioner;
2. the field or pool has not previously produced oil or gas for sale; and
3. oil or gas production from the field or pool would not otherwise be economically feasible.
4. Under AS 38.05.180(j)(2), the commissioner may not grant a royalty modification unless the lessee or lessees requesting the royalty modification make a clear and convincing showing that a royalty modification meets the three requirements set out above and is in the best interests of the state.

B. General Royalty Modification Terms

1. Under AS 38.05.180(j)(3) the royalty modification terms must provide for an increase or decrease or other modification of the state's royalty share by a sliding-scale royalty or other mechanism that shall be based on a change in the price of oil or gas and may also be based on other relevant factors such as a change in production rate, projected ultimate recovery, development costs, and operating costs.
2. Under AS 38.05.180(j)(4)(A) a modification to royalty may not be granted for the field or pool if the royalty modification would result in a royalty rate of less than 5 percent in amount or value of the production removed or sold from a lease or leases covering the field or pool.
3. Under AS 38.05.180(j)(5) a royalty reduction must include an explicit condition that the royalty reduction is not assignable without the prior written approval, which may not be unreasonably withheld, by the commissioner. The commissioner shall, in the preliminary and final findings and determinations, set out the conditions under which the royalty reduction may be assigned and may not grant a royalty reduction without an explicit condition that the royalty reduction is not transferable.

IV. DISCUSSION OF ROYALTY MODIFICATION CRITERIA

A. Leases Are Eligible For Consideration

The leases meet the requirements for consideration and all eleven subject leases proposed for royalty modification are committed in entirety to the Nikaitchuq Unit. AS 38.05.180(j)(1) allows modification of royalty for individual leases and unitized leases.

B. Reservoir Delineation: Discussion of Reservoir Geology and Engineering

1. Introduction to reservoir delineation.

The commissioner may grant royalty modification to allow for production from an oil or gas field or pool if the oil or gas field or pool has been sufficiently delineated to the satisfaction of the commissioner.

The area within the Nikaitchuq Unit for which royalty relief is sought lies offshore in the Beaufort Sea in the vicinity of Spy Island, approximately three miles north of Oliktok Point. The Nikaitchuq Unit is north of and contiguous with the northern edge of the KRU and the Milne Point Unit (MPU). The KRU is operated by ConocoPhillips and produces from the Cretaceous Kuparuk River Formation and shallower Schrader Bluff Formation. The BP-operated MPU field lies to the south-southeast of the Nikaitchuq Unit and produces oil from the Schrader Bluff, Kuparuk, and Triassic Sag River formations. The western edge of the proposed Nikaitchuq Unit is adjacent to the recently expanded Ooguruk Unit (OU) operated by Pioneer. Production from the OU is expected from the Kuparuk and Jurassic Nuiqsut sandstones.

Within the Nikaitchuq Unit, potential commercially recoverable reserves have been tested in both the Cretaceous Schrader Bluff and the Triassic Sag River formations.

Based upon the submitted application and the planned initial development, the request for royalty modification at Nikaitchuq is limited to the OA sand of the Schrader Bluff Formation. For the purpose of this application, the OA sand is defined in Kerr McGee Nikaitchuq #1 (API No. 50629231930000), completed in 2004, as the interval between 5034 feet measured depth (4127 feet subsea true vertical depth) and 5090 feet measured depth (4170 feet subsea true vertical depth).

ENI has adequately delineated the OA sand of the Schrader Bluff Formation in the Nikaitchuq area. Their drilling, testing, and evaluation programs appear to have highlighted the obvious risks inherent to developing viscous oil and identified the possible upside potential available through use of extended reach drilling and advanced completion technologies.

Although upside potential may also exist within the shallower Schrader Bluff N sand interval, the current lack of core, well test, or fluid data from this interval increases the risk and precludes it from being deemed delineated and included as part of this application. ENI plans to gather more data to thoroughly evaluate the N sand during the course of developing the deeper OA sand.

The Sag River Formation contains lighter oil than the Schrader; however, it is plagued with poor quality reservoir rock. The development potential is marginal at best unless there are significant advances in stimulation or enhanced oil recovery technology. Delineation of the Sag River Formation at Nikaitchuq to date has revealed limited reserves and similar test results to the analog at MPU where wells within the Sag River Formation consistently show initial flush production followed by steep decline within the first year. ENI is still evaluating the development potential of this interval and, as such, it has been excluded from this application.

2. Exploration History of the Area

Two key early exploration wells lie within several miles of the Nikaitchuq development area. The Unocal East Harrison Bay State #1 well lies near the northwest corner of the KRU, to the southwest of the Nikaitchuq Unit. The well was drilled in February 1977 to a measured depth of 9,809 feet, bottoming in argillite basement. The East Harrison Bay State #1 well logs appear to contain about 15 feet of oil-bearing Kuparuk Formation that appears cemented in the upper half. The Jurassic section looks silty on logs. The ARCO Kalubik #3 well, drilled in February 1998, lies to the south-southwest of the Nikaitchuq area. The well bottomed in the Jurassic at a measured depth of 7,000 feet. The well encountered a 40-foot-thick measured depth (MD) interval of Kuparuk C sandstone that appears on electric logs as oil-bearing, but siderite cemented in the upper 10 feet of the interval. On well logs the Jurassic interval contains silt with a 12-foot silty sand developed around 6,565 feet MD. The well was plugged and abandoned on March 6, 1998.

3. Drilling History

The first major exploration activity in the area in the early 1970s targeted the Ivishak Formation following the discovery of the prolific Ivishak Formation in Prudhoe Bay State #1 in 1967. The Hamilton Brothers Milne Point #18-1 was one of the early wells drilled on the Milne Point structure in 1970 in search of Ivishak and Lisburne objectives. This well encountered about 50 feet of tight oil-saturated sandstone that was not tested and a section of Kuparuk sandstone that tested at a rate of 875 BOPD. This discovery led to increased industry interest in the Milne Point area and led to exploration and delineation drilling for Kuparuk reserves. In the early 1980s the Sag River was cored in the Conoco Milne Point Unit #C-1 well and contained bleeding oil and gas. The Sag River Sandstone was also cored in the MPU #L-1 well and contained no visible porosity or staining and appeared tight on wire line logs.

In the early 1990s about a dozen wells were drilled to the west-southwest of the Nikaitchuq area with Jurassic sandstones and Kuparuk C sandstones as targets. The ARCO Kalubik #1 well encountered approximately 160 feet of productive Nuiqsut and Nechelik sandstone that tested approximately 336 BOPD (un-stimulated). In addition, the well penetrated an 85-foot section of Sag River Sandstone with calculated log porosities in the range of 15 to 22 percent. The Thetis Island #1 well also encountered an 80-foot section of porous Sag River sandstone with log-calculated porosities in the range of 16-24 percent. A pay section of Nuiqsut sandstone was also encountered that tested at an average rate of 120 BOPD with a high rate of 650 BOPD. Both the Kalubik #1 well and Thetis Island #1 well drilled through Brookian sandstones that contained mud log hydrocarbon shows.

In the late 1990s BP drilled several dedicated Sag River Sandstone test wells, including MPU #C-23, #K-33, #E-13A, 3F-33, #F-33A, and #F-73A. Alaska Oil and Gas Conservation Commission (AOGCC) production data indicate that several Milne Point wells have produced oil out of the Sag River Sandstone and two oil producing wells MPU F-33A and K-33, are currently shut-in. MPU #C-23 produced 378,012 barrels of oil between 1996 and 2001. MPU #F-33 produced 314,276 barrels of oil between September 1996 and May 1999 and was subsequently plugged and abandoned. MPU #K-33 has produced approximately 93,241 barrels of oil since 1997. MPU #E-13A produced 366,665 barrels of oil between 1995 and April 2001. MPU #F-33A produced approximately 661,099 barrels of oil since April of 2001. MPU #F-73A produced 13,430 and is now a water-alternating-gas injection (WAGIN) well. BP estimated the original oil-in-place (OOIP) at 62 MM STB oil and the reservoir area about 8500 acres based upon seismic and log data during an AOGCC Conservation Order hearing in May 1998. AOGCC reservoir data indicate that the oil commonly recovered from the Sag River sandstone has an API oil gravity of about 37 degrees. Total production from the MPU Sag River Sandstone has been 1,834,131 barrels of oil and 1,875,668 MSCF gas through October 2007. MPU Sag River recovery is less than 3 percent to date based on OOIP. The original GOR ranged from 784 – 974 SCF/STB. Production from the Sag River pool at MPU has been intermittent with extended shut-in periods since June 1999.

Between 2004 and 2005, Kerr McGee (KMG) drilled six wells in the Nikaitchuq and Tuvaq Units. Initially, the primary exploration target was the Sag River Formation; the Kuparuk Formation was a secondary target. Although the wells did not encounter reservoir quality sand in the Kuparuk, the well logs indicated that sands in the shallower Schrader Bluff Formation were prospective. KMG then adjusted the exploration program to thoroughly evaluate the Schrader Bluff Formation. Three of the six wells tested oil from the viscous Schrader Bluff or Sag River formations. In 2006/2007 KMG drilled two additional pre-development wells from Oliktok Point to further delineate and test the Schrader Bluff sandstone. The two wells are currently suspended.

4. Schrader Bluff Formation Tests

KMG Nikaitchuq #4

Approximately 3,000 feet of gross horizontal Schrader Bluff OA sand was drilled in this well, with approximately 2,270 feet of horizontal or lateral net pay, from a 30-foot true-vertical-depth net pay thickness. A two-week production test was performed on the well using an electric submersible pump (ESP) to aid in producing the 16–17 API crude. The well tested at rates up to 1,200 barrels of oil per day during periods of the initial test. Permeability estimated from the test was greater than 350 millidarcies and was confirmed from the analysis of the flow tests conducted on a whole core obtained from the well.

KMG Tuvaaq #1

The well was not tested. It penetrated 30 feet net pay Schrader Bluff OA Sand and 12 feet net Schrader Bluff N sand. There were no cores taken at Tuvaaq. Schrader Bluff N sand was interpreted to be oil-filled here and at Kigun #1 appeared unconsolidated with permeability estimated from 100-1000 millidarcies and porosity 25-35 percent.

KMG Kigun #1

The well was not tested. It penetrated 29 feet net pay Schrader Bluff OA sand and 30 feet net N sand. An MDT tool run sampled the Schrader Bluff OA fluids which were 18 degree API, GOR 59 SCF/STB and viscosity of 82 cp at 87 degree reservoir temperature. (Contamination of the samples with oil-based mud caused concern about the reliability of the sample estimates and properties.) Schrader Bluff OA sand core data indicated 25 percent to 38 percent porosity and up to 1,000 millidarcies permeability in the sandstone intervals.

KMG Oliktok Point I-1 KMG Oliktok Point I-2

These two wells were drilled by KMG during the 2006/2007 drilling season as pre-development wells to further test and delineate the Schrader Bluff reservoir. These wells have been suspended. Results from these wells are currently held confidential under AS 38.05.035(a)(9).

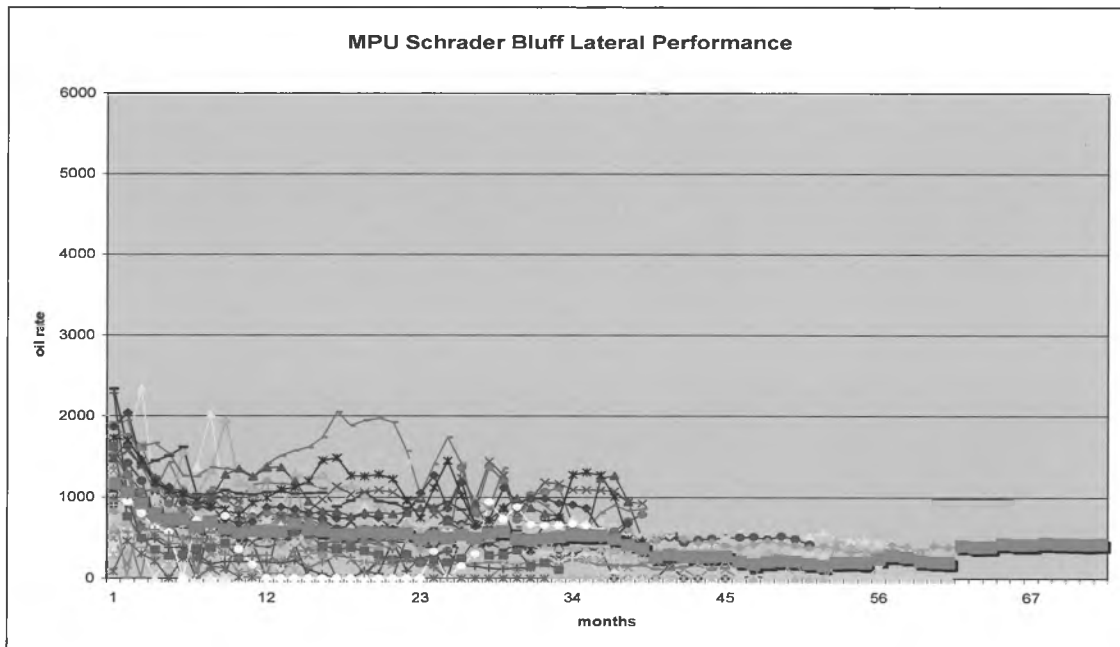
5. Analog Schrader Bluff Formation Performance

Milne Point Unit (MPU) Schrader Bluff Pool (Figure 1), Kuparuk River Unit (KRU) West Sak Pool (Figure 2) and Prudhoe Bay Unit (PBU) Polaris and Orion pools – Figure 3, represent analog Schrader Bluff Formation horizontal well performance. Each of the pools was developed initially with vertical or slanted completions. More recently a number of horizontal lateral and multi-lateral wells have been completed in each of these pools. MPU and KRU Schrader Bluff wells show a distinct, lower rate performance than the newer developed Polaris and Orion Pool wells. A significant portion of the performance difference is likely due to differences in fluid quality. Within the Schrader Bluff Formation / West Sak, developments oil gravities can vary between 15-24 degrees API and viscosity can vary between 5-130 centipoise. To date, development has been limited to those areas with higher API Gravity and lower viscosity. Later Schrader Bluff Formation developments are building on earlier techniques by going from vertical to

horizontal and multilaterals wells. The horizontal and multilaterals should consistently outperform the older wells because more formation is exposed and the completions are more efficient.

The wells in each Schrader Bluff Formation pool exhibit early flush production for six to 12 months. The PBU Schrader Bluff completions show slightly higher initial rate profiles followed by relatively steep decline. The average MPU Schrader Bluff completion (heavy bright green points and line) declined from 1200 bopd to 500 bopd at 12 to 40 months. KRU West Sak lateral completions have performed similar to MPU Schrader Bluff.

Figure 1. MPU Schrader Bluff Formation lateral performance and average performance (heavy green).



6. Reservoir delineation determination.

ENI has adequately delineated the OA sand of the Schrader Bluff Formation in the Nikaitchuq area. Their drilling, testing, and evaluation programs appear to have highlighted the obvious risks inherent to developing viscous oil and identified the possible upside potential available through use of extended reach drilling and advanced completion technologies.

Figure 2. KRU West Sak sands lateral performance and average performance (heavy orange).

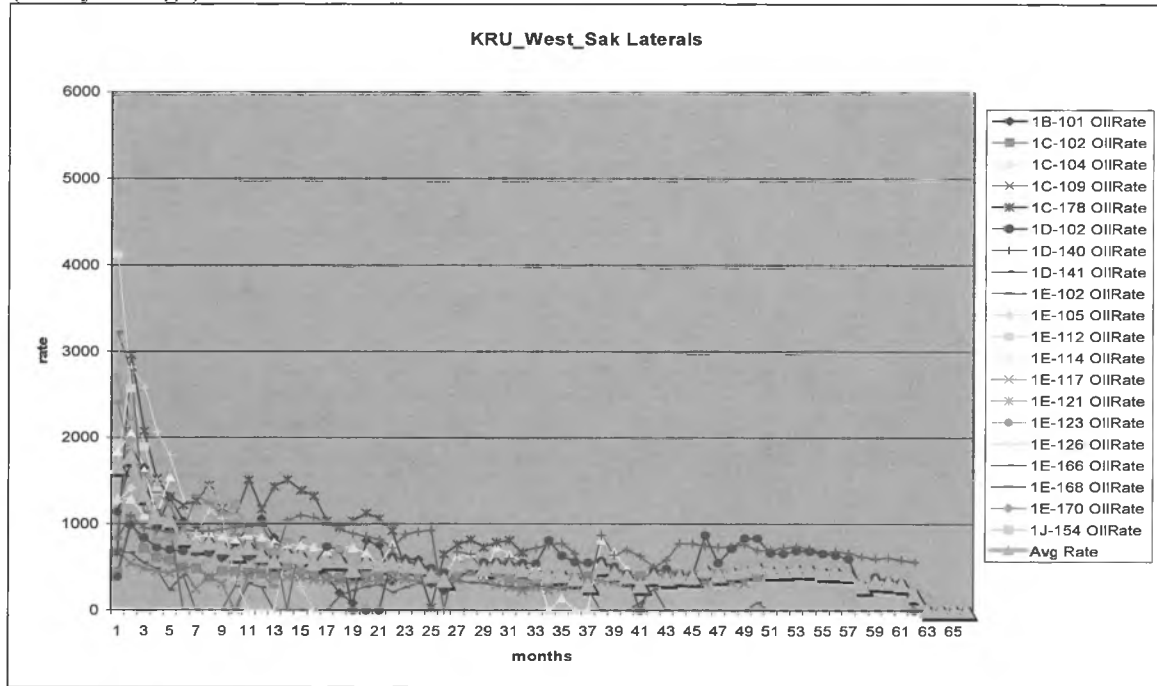
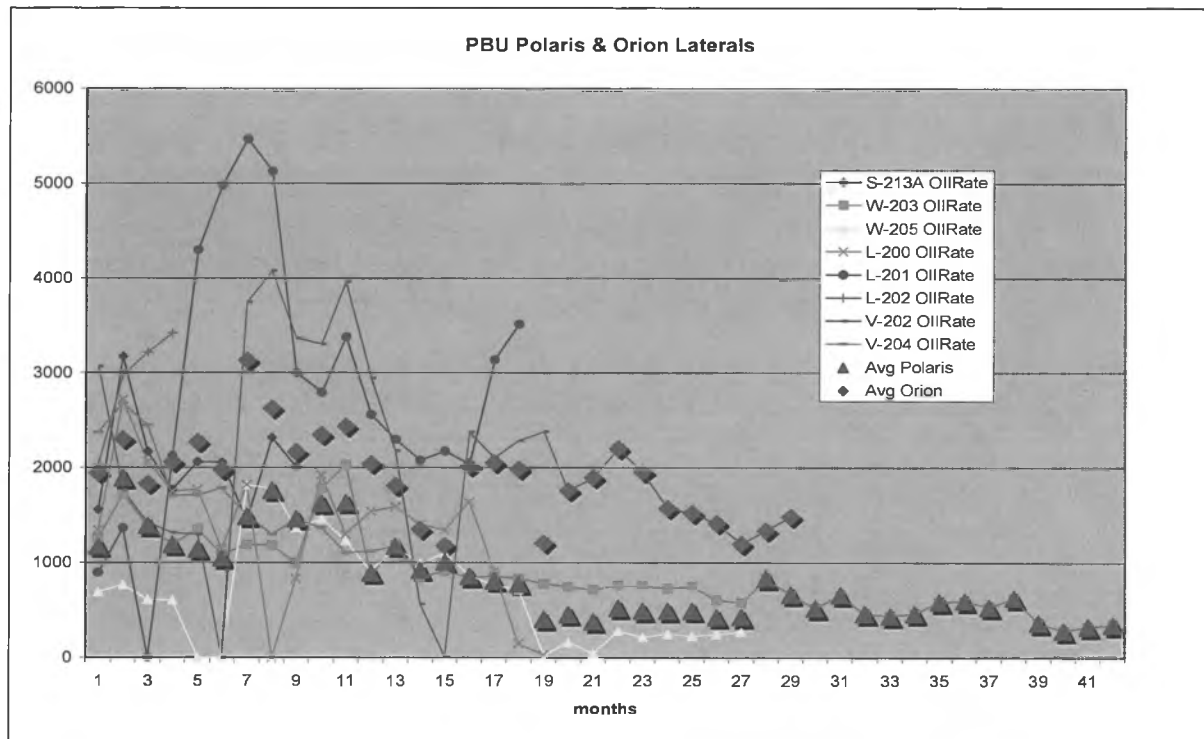


Figure 3. PBU Polaris and Orion Schrader Bluff Formation initial performance.



ENI stated that their plan is to develop Nikaitchuq Schrader Bluff Formation with horizontal wells. Their prognosis of performance can be compared to the analogs by evaluating average Schrader Bluff well performance from initial completion to date. There are up to seven years of production history for the various Schrader Bluff Formation horizontal and lateral wells. Orion appears to be more productive so far but the long term performance has yet to be defined. ENI appears to estimate their development will improve on the previous KRU and MPU Schrader Bluff completions by using the latest technology, namely very long horizontal and or multi-lateral completions. ENI's cases align reasonably with the MPU Schrader Bluff and KRU West Sak and PBU Polaris average performance. PBU Orion performance is notably better than ENI's high case average rates. Analyses of oil samples taken within the OA sand in the Nikaitchuq area demonstrate measured oil viscosities of 95–188 centipoise. This is heavier than the average viscosity of production from existing KRU, MPU and PBU Schrader Bluff developments. In addition, the Nikaitchuq development will include construction of a new standalone facility. The KRU, MPU, and PBU Schrader Bluff pools had existing infrastructure and production from other formations to support the additional development. Both of these factors increase the risk and make this project more economically challenged compared to existing heavy oil developments.

C. No Previous Sale of Produced Oil or Gas

The pools underlying the leases have not previously produced oil or gas for sale.

D. Economic Analysis

ADNR used its own in-house probabilistic economic model (ADNR Model) for the Nikaitchuq development to independently assess the financial performance and ultimate economic effects of a royalty modification for both Eni and for the State of Alaska. Eni shared with the state portions of its proprietary economic model, but the state chose to use its own model that incorporated many input assumptions provided by Eni.⁴

ADNR closely examined the assumptions and methods currently in use by the U.S. Minerals Management Service (MMS) for the Deep Water Royalty Relief Program. The MMS has developed an in-house proprietary probabilistic economic model for Royalty Suspension Viability Program. ADNR adopted an approach similar to that of the MMS by applying the quantitative results from the ADNR model to a prudent-investor decision framework. The ADNR decision framework is confidential. It is designed to replicate the kind of analytical framework used by industry for making prudent oil and gas investment decisions under uncertain conditions involving significant capital outlays and lengthy project life cycles.

⁴ Eni has submitted financial and technical data and analyses and requested that they be held confidential in accordance with AS 38.05.035(a)(9). Thus this section does not discuss any confidential information concerning Eni's geologic, engineering and cost data. These documents are included and discussed in detail in the confidential *Economic Analysis and Internal Decision Process*, (Attachment 6).

The prudent investor standard is maintained throughout the project evaluation process. Under this standard, ADNR incorporates a collection of project performance benchmarks that are consistent with industry norms.

To obtain royalty relief the applicant must show by clear and convincing evidence that without royalty modification the project is not economically feasible. Nikaitchuq is an offshore, heavy oil prospect with relatively high expected exploration and development costs and low expected production possibilities. The final analysis of Nikaitchuq project development conducted by ADNR pursuant to the Eni royalty modification application suggests that, under reasonable assumptions about future oil prices and without some form of royalty relief, this project would not be sanctioned for funding and development.

In its simplest form, the ADNR Model describes project cash-flows for the Nikaitchuq development over a 50-year time horizon. The ADNR Model incorporates expected investment, production, price, revenue, and cost. It incorporates fiscal system attributes, including state and federal tax, state production tax (including the recent ACES legislation)⁵, and royalty obligations, as well as other important commercial relationships, such as facility sharing and pipeline transportation charges.

The ADNR in-house model is flexible enough to allow ADNR to evaluate the effects of changes to the fiscal system. The model provides a platform for systematic evaluation of the effect of a change to the royalty rate. The model calculates the changes to the various financial metrics that result from a change in the royalty rate. These metrics include annual and cumulative discounted and undiscounted cash flow, years to payout, net present value (NPV), expected monetary value (EMV), and internal rate of return (IRR) on investment, as well as state revenues. Also, ADNR used its model to carry out sensitivity analysis of key driver assumptions and to characterize certain price, production, and cost variables in terms of probability distributions to evaluate how uncertainty among these drivers affects key project metrics and state revenues.

Eni furnished ADNR with 200 realizations of project production that depict the range of values and probabilities for the many reservoir factors that determine ultimate reservoir recovery (e.g., aerial and vertical extent, rock characteristics, fluid composition and properties). These 200 Eni realizations represent the universe of possible resource recovery outcomes for ADNR's Monte Carlo analysis that fit the well-test data. The ADNR model samples repeatedly from this universe of production realizations, as well as from volatility inherent in price formation, as characterized in the mean reversion price model (see below), to generate a distribution of net present value (NPV) outcomes for the Nikaitchuq project. The central tendency (mean and median) and dispersion (variance) of the NPV outcomes depict project performance uncertainty and speak to the dimensions of ADNR's prudent-investor decision framework mentioned above.

ADNR incorporated the applicant's input data into its model along with its own assumptions about the path of uncertain future prices to derive independent results for the

⁵ See HB2001 (11/15/2007).

economic feasibility of the Nikaitchuq project. The ADNR Model examines a range of possible inputs to derive a P50, or median, outcome from a Monte Carlo simulation. The P50 result is the value where 50 percent of the outcomes lay below this point and 50 percent of the outcomes lay above the P50 outcome. The ADNR Model uses Palisades Software's "@Risk" Monte Carlo software application to run the simulations and determine risk-weighted outcomes reported in the confidential supplement to this *Final Findings and Determination* (Attachment 7).

Calculating risk weighted outcomes is critical to a full analysis of a project. The probabilistic rate profile, determined based on the applicant's reservoir simulation results, is combined with pricing to determine the project revenue stream. Annual Alaska North Slope West Coast (ANSWC) crude oil prices were generated from an Ornstein-Uhlenbeck type Mean-Reversion price model⁶ with parameters estimated as described by Schwartz, (1997)⁷ using annual price data for ANSWC crude as reported by Platt's. The starting ANSWC delivered price used in the model is \$67 per barrel, the average price for 2007. The risk weighted cost profiles are then matched to the revenue stream generated by the probabilistic price and production models. This yields an NPV distribution. The mean of the NPV distribution is the EMV for the entire project that incorporates uncertainty and can be compared "apples-to-apples" with other versions of the project.

ADNR analyzed various scenarios to explore Nikaitchuq project performance with and without royalty modification. DNR approves royalty modification only when it believes a project will not go forward without it. This means that the impact to royalty revenues to the state is the difference between the royalty revenues with royalty modification as was prescribed in the DNR decision and zero. Even under low price scenarios, ADNR determined that the state can expect to receive an additional \$100 million over the life of the project.

If it is assumed that the project could have gone forward without royalty modification (again, not what ADNR assumes) the impact would be as indicated in Table 1. This table presents several possible price scenarios and the indicated change to the state royalty cash flow stream.

In Table 1 the scenarios labeled "\$43 and Above (Sustained)" and "\$40 Sustained" simply use a flat price deck for "Alaska North Slope West Coast" (ANSWC) crude oil (before inflation) for the life of the project, the price does not vary from year-to-year. An oil price of \$40 is always just below the \$42.64 royalty modification threshold and thus results in 5 percent royalty rates for every barrel of oil produced from the reservoir for the life of the project and the greatest negative impact to overall state royalty revenues.

⁶ Dixit & Pindyck, 1994, http://www.puc-rio.br/marco.ind/sim_stoc_proc.html#mc-mrd.

⁷ The Stochastic Behavior of Commodity Prices: Implications for Valuation and Hedging", Schwartz, E., *Journal of Finance*, 1997, Volume 52, issue 3, 923-973

Table 1. Change in Alaska royalty revenues if royalty modification were not necessary and project produced oil without royalty modification.

Price Scenario	Impact on State of Alaska Royalty Revenue ("With Royalty Modification Per Decision" Minus "Without Royalty Modification", 5% discount rate)
\$43 and Above (Sustained)	\$0 million
DNR Price Model	(\$39 million)
\$40 Sustained	(\$160 million)

The "DNR Price Model" scenario does not use a constant or "sustained" price for the life of the project (i.e. flat price deck) as is the case with the other two scenarios in Table 1. We use a forward-looking, Monte Carlo-based "mean-reversion" model, as discussed above. This price model creates a price forecast where oil price fluctuates over time, simulating real-life price variability similar to what history has shown. The price for 2007, \$67 per barrel ANSWC, was taken from U.S. Energy Information Agency's most recent price projection for West Texas Intermediate (WTI) crude, and adjusted for ANS-WTI basis by taking the previous 12-month average difference between these two prices. The model reverts to DNR's expected mean value of \$53 per barrel, over time.

The ADNR has determined that under ADNR's price and discounting assumptions, the project attributes furnished by Eni, and the existing lease royalty rates in effect prior to this *Final Finding and Determination* (16.6667 percent fixed royalty rate and the 12.5 percent fixed royalty with 30 percent NPS for ADL 391283), the Nikaitchuq project does not meet prudent-investor standards for economic feasibility. ADNR concludes further that the royalty modification terms and conditions stipulated in Section IV.B would improve project economics. Eni represents that royalty modification would make project sanction more likely.

V. PUBLIC COMMENTS

On November 30, 2007, ADNR issued a Preliminary Findings and Determination to respond to Eni's royalty modification application. The public was invited to comment on the preliminary decision for thirty days, ending January 7, 2008 (Attachments 3 and 4).

No comments were received from the public.

VI. STATE'S PROPOSED ROYALTY MODIFICATION

A. Royalty Modification Requirements for the Nikaitchuq Project

1. Eni's application for royalty modification on ADLs 388571, 388572, 388574, 388575, 388577, 388580, 388581, 388582, 388583, 390615, and 390616, and ADL 391283 meets the requirements for consideration under AS 38.05.180(j)(1). Eni has paid the filing fee and submitted a complete application for the royalty modification including financial and technical data that meet the requirements of 11 AAC 88.105, 11 AAC 83.185, 11 AAC 05.010(a)(10)(H), and AS 38.05.180(j)(6).
2. The Schrader Bluff pool has been sufficiently delineated to the satisfaction of the commissioner for the purpose of considering royalty modification; this pool has not previously produced oil or gas for sale.
3. Eni has shown that oil or gas production from the Schrader Bluff pool would not otherwise be economically feasible.
4. Eni has made a clear and convincing showing that a modification of royalty meets the requirements of 38.05.180(j)(1)(A), and is in the best interests of the state.

B. Royalty Modification Terms for the Nikaitchuq Project

1. Royalty modification pursuant to the terms herein is granted to Eni US Operating Co. Inc. (Eni), as operator and 100 percent working interest owner of the Nikaitchuq project (Project), on ADLs 388571, 388572, 388575, 388574, 388577, 388581, 388582, 388583, 390615, 390616, and 391283. Royalty modification is denied for ADL 388580 because there was no apparent resource allocated to this lease.
2. Only production from Nikaitchuq Unit's Schrader Bluff OA reservoir, as delineated under this Findings and Determination, shall be eligible for royalty modification. To receive royalty modification on production, the lease must be committed to an approved participating area within six years of the date of Project sanction. After six years, any subject lease or portion of a subject lease not committed to an approved participating area for the Nikaitchuq Schrader Bluff OA reservoir shall revert to the respective individual lease royalty rates that were in effect immediately prior to this Findings and Determination.

3. If the Project, not materially changed from that set out in the October 16, 2007, royalty modification application, is not sanctioned by all working interest owners by February 28, 2008, this royalty modification decision is rescinded.
4. Within 30 days following the date of Project sanction, the working interest owners shall provide ADNR with the Project sanction documents, approvals for expenditure, and other documents supporting the technical and financial data submitted with Project sanction documents excluding any proprietary data. ADNR agrees to keep all such data confidential.
5. If six years following the date of Project sanction total actual Project spending starting December 1, 2007, does not meet \$822 million in nominal dollars, then this royalty modification is rescinded. If 11 years following the date of Project sanction total actual Project spending does not meet \$1.398 billion in nominal dollars, then this royalty modification is rescinded. The ADNR may audit the working interest owners' spending on this Project to determine compliance any time between the sixth and the 13th year following Project sanction. If at either cost threshold juncture this royalty modification is rescinded, then Eni will refund to the State of Alaska the difference between the royalty which would have been due at the royalty rates that were in effect immediately prior to the effective date of this Findings and Determination and the royalty due at the modified royalty rate, with interest as set forth in AS 38.05.135(d).
6. The NPS lease regulations set out in 11 AAC 83.201 – 11 AAC 83.295 remain in full force and effect for ADL 391283, except that the cost to the applicant for the application for royalty modification will not be included in any NPS lease Development Account balance.
7. (a) Nikaitchuq royalty modification mechanism implemented as follows:
 - i. Original lease rates are 12.5 percent for ADL 391283 and 16.67 percent for ADLs 388571, 388572, 388575, 388574, 388577, 388581, 388582, 388583, 390615, and 390616.
 - ii. For the first 25 years following the date of first sustained production, when Alaska North Slope West Coast ("ANS WC") delivered crude prices are below the threshold price per barrel as adjusted by inflation, then production from the Nikaitchuq Schrader Bluff OA reservoir on the subject lease will pay a 5 percent royalty. The ANS WC crude price for the month of production is the average assessment by Platt's Oilgram Price Report and Reuters online data providing service, of the spot price for ANS delivered on the West Coast. The average assessment of the spot price for ANS by each reporting service is the average of the midpoints of the high and low closing assessments for the spot price for ANS for all days during the month of production for which closing assessments are

reported. The threshold price shall start at \$42.64 per barrel. This threshold price will be adjusted annually for inflation starting on May 1, 2008, and shall be adjusted on each May 1 thereafter. The inflation adjustment shall be $(1 + \text{inflation rate})$ multiplied by the previous year's inflation-adjusted threshold price. The inflation rate shall be determined by taking the previous year's annual implicit price deflator for GDP (initially, for the year 2007) as reported by the end of April of each year, dividing that deflator by the two-years-previous annual implicit price deflator (initially, for the year 2006), and then subtracting 1. The source of the inflation data shall be the Department of Commerce Bureau of Analysis (BEA) U.S. Economic Accounts-GDP. National Income and Productions Account (NIPA) Table 1.1.9. When the monthly ANS WC oil price is above the threshold, royalty rates for production attributable to such month(s) shall return to the original lease royalty rates.

iii. This royalty modification shall be terminated 25 years following the date of first sustained production and at that time royalty rates shall revert to the respective individual lease royalty rates that were in effect immediately prior to this Findings and Determination.

(b) For the 18th through the 120th months after first commercial production from the Nikaitchuq Schrader Bluff OA reservoir, if production from all of the subject leases averages below 4,000 barrels of oil per day for any previous twelve month period, full royalty modification rates of 5 percent shall be in effect for all production from the Nikaitchuq Schrader Bluff OA reservoir, regardless of oil price. Provided, however, nothing in this provision shall prevent Eni from applying for royalty modification under AS 38.05.180 (j)(1)(B) or (C).

8. In the determination of royalty value of oil or gas from any of its properties, Eni shall waive any rights to a transportation deduction for the pipeline constructed pursuant to the Easement granted on ADL 417493. This waiver shall remain in effect even if such pipeline is converted to a common carrier.
9. If any working interest owner should contract to use any processing facilities at any time for production from the reservoirs delineated and leases covered in this Findings and Determination, that working interest owner shall furnish ADNR the facilities contract, including information regarding the fee structure and volumes processed unless such contract prevents disclosure of such information. This information will be kept confidential by ADNR. The working interest owner shall also furnish produced oil, water, and gas volumes on a monthly basis broken down by individual working interest owner.
10. Should any third party petition the Nikaitchuq Unit facility owners to contract for use of any unit facilities, the cost of use shall be based on market rates. Any

resulting contract covering facilities access or use shall be shared with the ADNR. ADNR agrees to keep all such information confidential.

11. This royalty modification is not assignable without prior written approval of the ADNR commissioner, which shall not be unreasonably withheld. The assignee must be fit, willing, and able to satisfy all of the duties and obligations attached to this royalty modification and all other lease terms.

12. If at any time royalty modification is rescinded, the terms and conditions of this Findings and Determination shall terminate, with two exceptions. First, the provisions of Term 8 shall survive the termination of royalty modification. Second, all obligations to keep information confidential that was submitted pursuant to this Findings and Determination shall survive the termination of royalty modification.

VI. PROPOSED FINDINGS AND DETERMINATION

After detailed consideration where all the materials presented by the applicant were reviewed and incorporated into our analysis, the ADNR has determined that Eni meets the necessary requirements and that royalty modification for the Nikaitchuq development project is warranted under the terms established in Section IV of this finding and determination.



Thomas E. Irwin
Commissioner

1/11/08
Date

cc: Kevin Banks, Director, Division of Oil and Gas
Antony Scott, Senior Commercial Analyst, Division of Oil and Gas
Jeff Landry, Department of Law