Nikaitchuq Development
Royalty Modification
Application

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

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

August 29, 2006

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I. BACKGROUND

On January 11, 2006, Kerr-McGee Oil & Gas Corporation[1] (KMG) as operator of the Nikaitchuq Unit and on behalf of itself and ENI Petroleum Exploration Co. Inc. (ENI) submitted an application to the commissioner of the State of Alaska Department of Natural Resources (DNR) for modification of royalty under AS 38.05.180(j)(1)(A) (Attachment 1). This Preliminary Findings and Determination responds to the royalty modification application as required under AS 38.05.180(j)(8).

KMG has applied for royalty modification on 14 leases which overlie the Schrader Bluff and Sag River pools. They request 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 twelve 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.

A. Procedure

The commissioner will publish this Preliminary Findings and Determination and give public notice of a 30-day public comment period (Attachment 2) 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 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. Within 30 days of the close of the public comment period the commissioner will prepare a summary of the public comments, make a Final Findings and Determination, and with the applicant's consent, amend the applicant's lease(s) or unitization agreement(s) consistent with the Final Findings and Determination. The commissioner's Final Findings and Determination regarding a royalty reduction is final and not appealable to the court.

II. SUMMARY OF KMG'S APPLICATION FOR ROYALTY MODIFICATION

On January 11, 2006, KMG, on behalf of itself and ENI submitted an application (Attachment 3) to the DNR commissioner for modification of royalty on 14 leases, ADLs 355021, 355024, 388571, 388572, 388574, 388575, 388577, 388578, 388580, 388581, 388582, 388583, 390615, and 390616 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) KMG submitted a complete application with the required $250.00 filing fee.

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

A. Lease Summary

KMG has applied for royalty modification on 14 leases. Twelve of the leases are committed to units. ADL 355024, a net profit share (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 Tuvaaq 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 4)

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 net profit share for the state. Effective June 1, 1985, ADL 355024 was committed in part to the Kuparuk River Unit (KRU) and in part to the Kuparuk Participating Area. 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 net profit share for the state. Effective April 27, 1992, ADL 355021 was committed in its entirety to the Milne Point Unit (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 Kuparuk Participating Area (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 Nikaitchuq Unit, and effective August 21, 2004, ADLs 388571, 388572, 388574, 388575, 388577, and 388578 were committed in their entirety to the Tuvaaq 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 ADL 355021. The royalty modification application is limited solely to the segments of these leases in which KMG and ENI retain working interest ownership (Attachments 3, 4A, 4B, and 5).

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 Tuvaaq 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 Nikaitchuq Unit which 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. A total of six wells were drilled in the Nikaitchuq area in the 2004 and 2005 winter drilling seasons. During the first quarter of 2004, Kerr-McGee drilled two exploration wells in the adjacent Nikaitchuq Unit, the Nikaitchuq #1 and #2 wells to the east of the proposed Tuvaaq Unit. The Tuvaaq #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, Nikaitchuq Unit was formed and effective August 21, 2004, Tuvaaq Unit 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 the division held several working sessions with KMG throughout the fall. KMG submitted 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 Tuvaaq units, surrounding acreage such as ADLs 390615 and 390616, as well as 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.
- 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 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 to Oliktok Point and provide fuel, secondary recovery fluid and power to the gravel island.

C. Royalty Modification Request

The 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 16.6667 percent to a fixed royalty rate of 5 percent.

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.
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. 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. STATE'S PROPOSED ROYALTY MODIFICATION

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 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 and Sag River pools have been sufficiently delineated to the satisfaction of the commissioner for the purpose of considering royalty modification; 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)(1)(A), 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 oil or gas production from the field or pool would not otherwise be economically feasible. The analysis the DNR has performed indicates that KMG has failed to show that this is true for the Nikaitchuq development project.

V. DISCUSSION OF ROYALTY MODIFICATION REQUIREMENTS

A. Leases are eligible for consideration.

The leases meet the requirements for consideration, six of the subject leases proposed for royalty modification are committed in entirety to the Tuvaaq Unit, four to the Nikaitchuq Unit, one to the Milne Point Unit, one to the Kuparuk River Unit, and two are non-unitized leases. AS 38.05.180(j)(1) allows modification of royalty for individual leases and unitized leases.

B. The pools are sufficiently delineated.

1. Introduction

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 Kerr-McGee 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 Nikaitchuq Unit 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 4865 feet measured depth (MD) (3999 feet subsea TVD) and 5096 feet MD (4174 feet subsea TVD). The Sag River pool is defined in Nikaitchuq #1 as the interval between 10359 feet MD (8631 feet subsea TVD) and 10738 feet MD (9039 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 Kuparuk River and Milne Point units.

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

2. Early Exploration History of the Area

Two early key exploration wells lie within several miles of the proposed unit area. The Unocal East Harrison Bay State #1 well lies near the northwest corner of the Kuparuk River Unit, 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 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 sandstone following the discovery of the prolific Ivishak sandstone in Prudhoe Bay State #1 in 1967. The Hamilton Brothers Milne Pt. #18-1 was one of the early wells drilled on the Milne Point structure in 1970 in search of Ivishak and Lisburne formation 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 lead to increased industry interest in the Milne Point area and lead to exploration and delineation drilling for Kuparuk reserves. In the early 1980s the Sag River was cored in the Conoco Milne Pt. Unit #C-1 well and contained bleeding oil and gas. The Sag River Formation 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 Formation 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 Formation 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 proposed Nikaitchuq Unit 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 1200 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 – 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

Kerr-McGee 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 4/19/04 Kerr-McGee announced that the Nikaitchuq 1 well "production tested more than 960 BOPD of 38 degree API crude" from the Sag River Formation between the depth of 10408 – 10472 feet MD (8679 – 8741 feet subsea TVD). The Sag River Sand was tested for 210 hours of which there were fluids being 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 utilizing instantaneous rates as plotted in the operator's report. GOR was 937 SCF/STB during the test. Well head pressure (WHP) fluctuated during the test mainly caused by water loading and gas slugging. The final WHP ranged between 300 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.

Kerr-McGee 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 Sand and permeability measured 2 millidarcies indicating tight reservoir rock.

Kerr-McGee Nikaitchuq #3
A 3000 foot horizontal section was drilled with approximately 1834 feet of net pay in the Sag River Sand. The Sag River was tested using a pump for 81 hours after oil surfaced. The initial rate declined from 1327 BOPD at day one to 760 BOPD (at 81 hours) of 32 degree API oil. Solution GOR averaged about 230 SCF/STB during the test. Well head pressure stabilized at 130 psi and pump intake pressure down hole finished at 1230 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

Kerr-McGee Nikaitchuq #4 (confidential well)
Approximately 3000 feet of gross horizontal Schrader Bluff formation was drilled in this well, with approximately 2270 feet of net pay, from a 30 foot 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 1200 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.

Kerr-McGee Tuvaaq (confidential well)
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.

Kerr-McGee Kigun (confidential well)
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^{o} API, GOR 59 SCF/STB and viscosity of 82 cp at 87^{o} 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 – 38 percent porosity and up to 1000 millidarcies permeability in the sandstone intervals.

9. 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 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 1200 bopd to 500 bopd at 12 to 40 months. KRU West Sak lateral completions performed similar to MPU Schrader Bluff.

KMG has stated 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 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 their development will improve on the previous KRU and MPU Schrader Bluff completions by using latest technology, namely horizontal and or multi-lateral 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. Conclusion

KMG has adequately delineated the Schrader Bluff Formation in the Nikaitchuq area. Their 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).

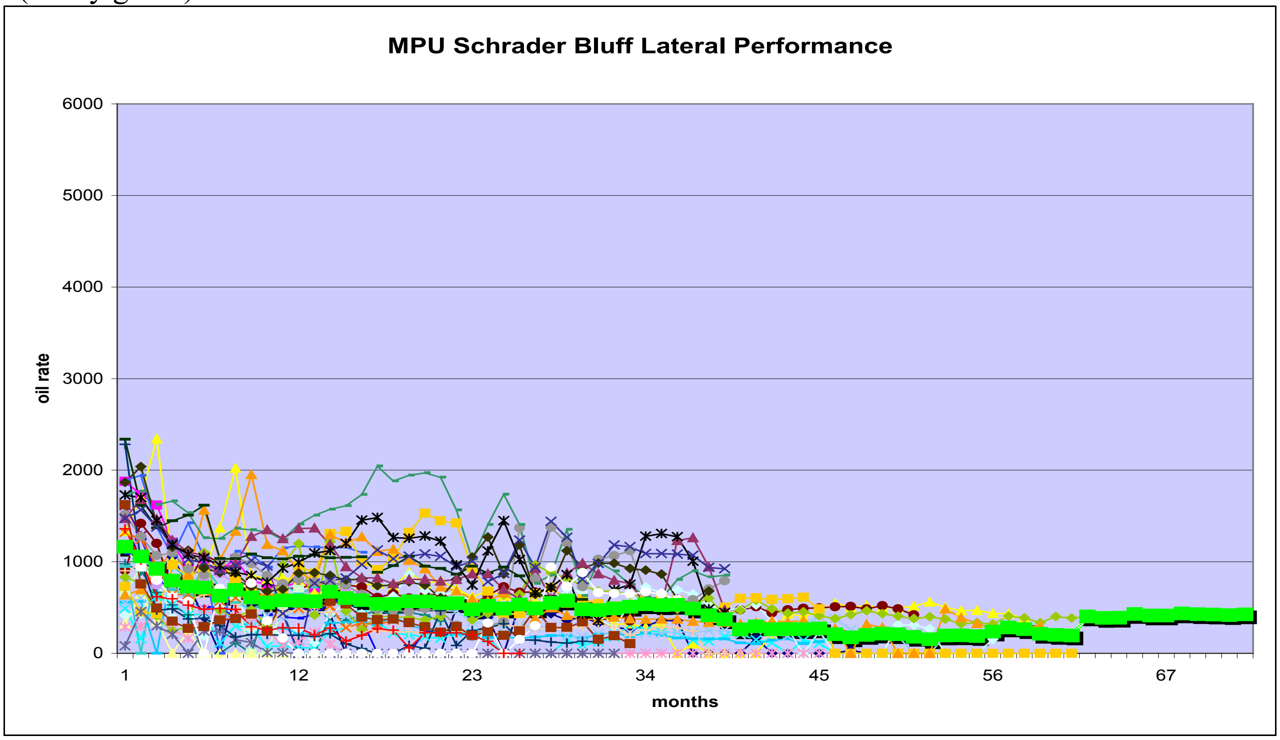


Figure 2. KRU West Sak sands lateral performance and average performance (heavy orange).

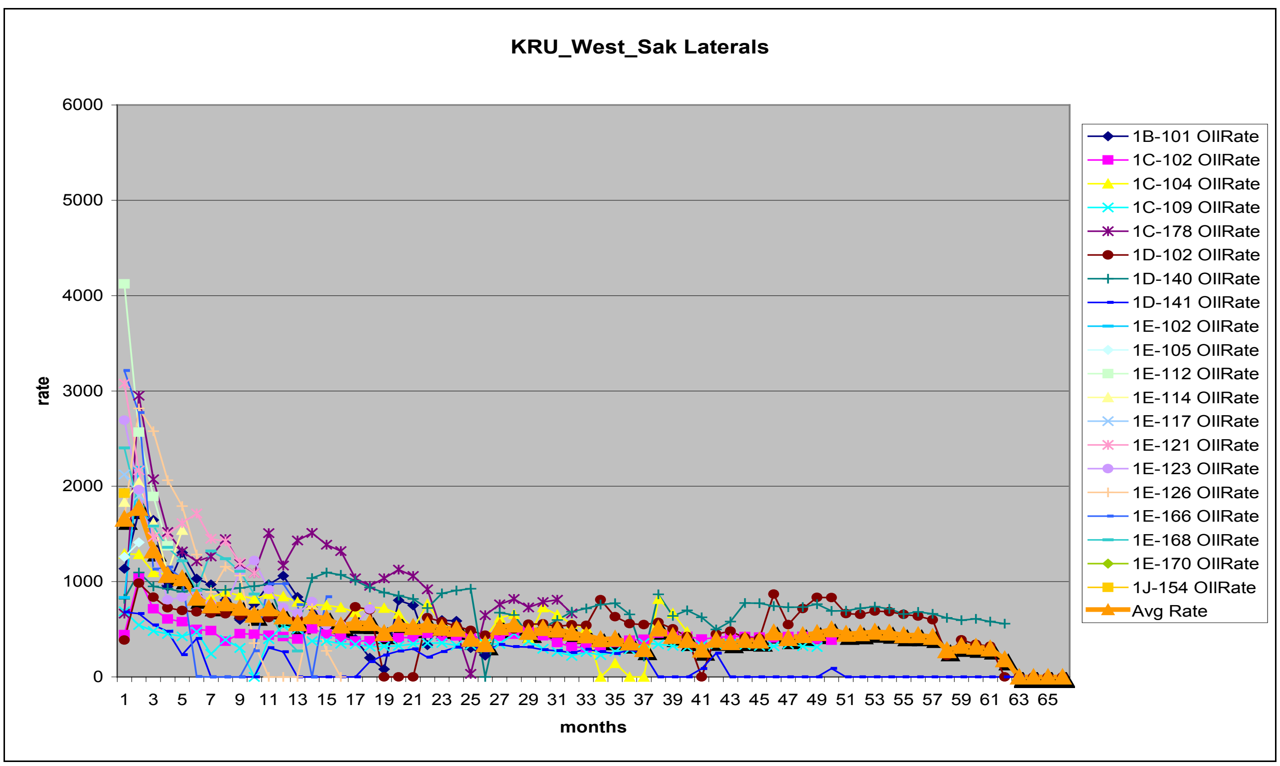


Figure 3. PBU Polaris and Orion Schrader Bluff Formation initial performance.

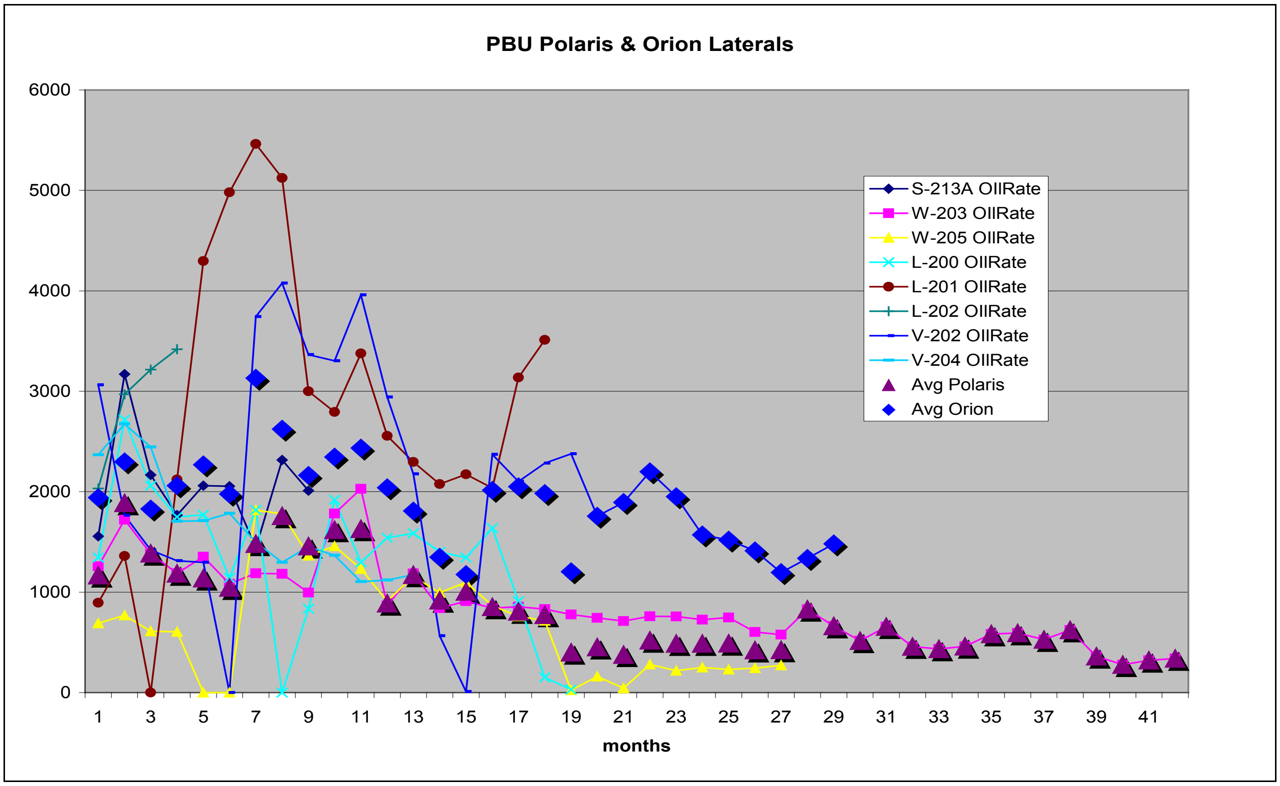
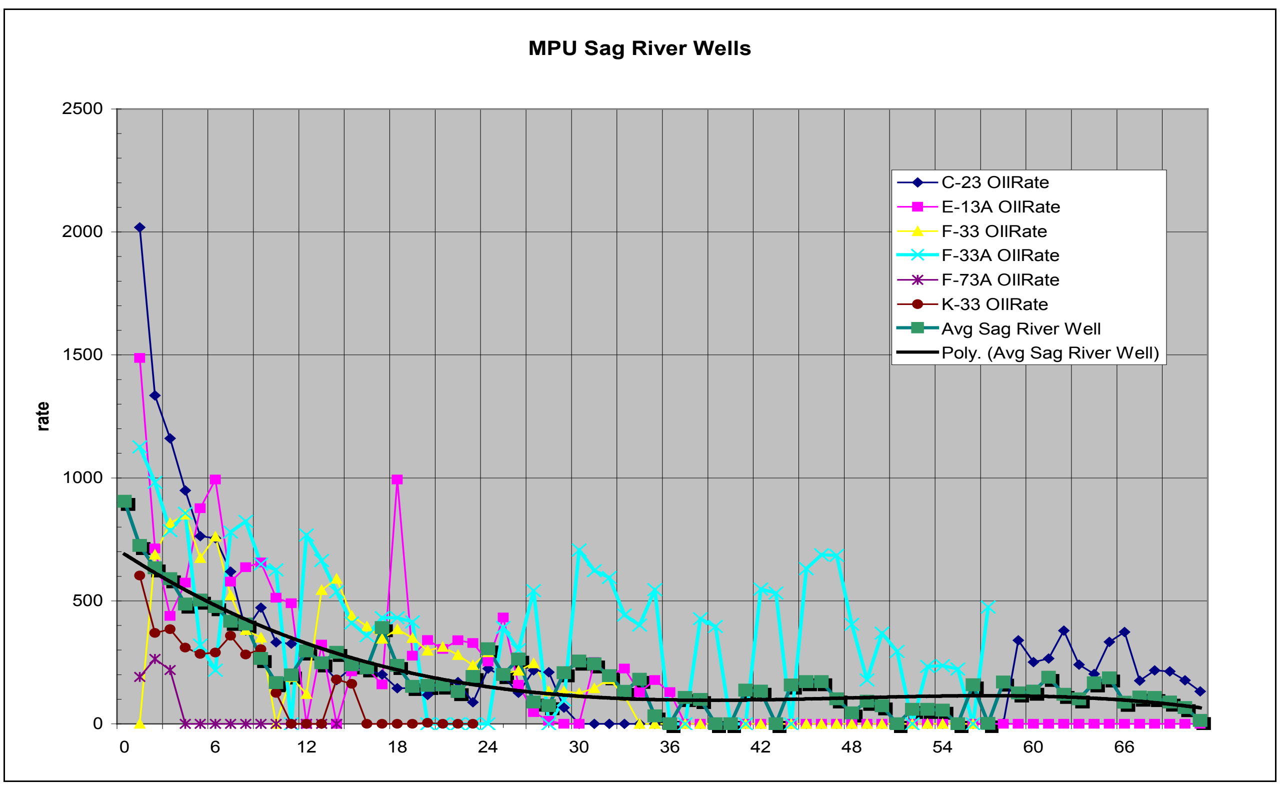


Figure 4. MPU Sag River Formation initial well performance.



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, (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. This is not the case today, at the writing of this decision.

E. Economic Analysis

DNR studied 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 closely 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-Uhlenbech type Mean-Reversion price model[2] 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 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.

[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

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).

DNR and KMG models did not produce identical results. The numerous work sessions and presentations (Attachment 6) served to resolve differences in modeling between DNR and KMG; and while the resulting DNR model reflects substantial 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,
2. oil price assumptions,
3. TAPS tariffs assumptions,
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 pays, on a discounted basis, about $120 million less in taxes than under the previous fiscal regime. This is largely the result of the workings of the various parts of the PPT. 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. 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.

VI. PROPOSED FINDINGS AND DETERMINATION

After detailed consideration where all the materials presented by the applicant were reviewed and incorporated into our analysis, the DNR has determined that any royalty modification for the Nikaitchuq development project is not warranted. Since the Nikaitchuq royalty modification application was filed by the operators, newly implemented changes to the tax structure for the State of Alaska have materially improved the economics of this project. Therefore, the royalty modification is hereby denied.

8/29/06

Michael L. Menge
Commissioner

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

1. AS 38.05.180(j)
2. Copy of Public Notice text and Affidavits, (Affidavits to be attached at completion of public notice period)
3. Request for Royalty Modification, Kerr-McGee, January 11, 2006.

4 A. Nikaitchuq Development Area Map
4. B. 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

   Econon 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

ATTACHMENT 1
AS 38.05.180(j)

AS 38.05(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 final findings and determination; the Commissioner's final 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 final 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 2
Copy of Public Notice Issuance
(To be included with Final Findings and Determination)

ATTACHMENT 3
Nikaitchuq Royalty Modification Application, Kerr McGee, January 11, 2006

KERR-McGEE OIL & GAS CORPORATION
16666 Northchase • Houston, TX 77060

DAVID HENKE
SENIOR INTERNATIONAL NEGOTIATOR

PHONE (281) 673-6337
FAX (281) 673-5045

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

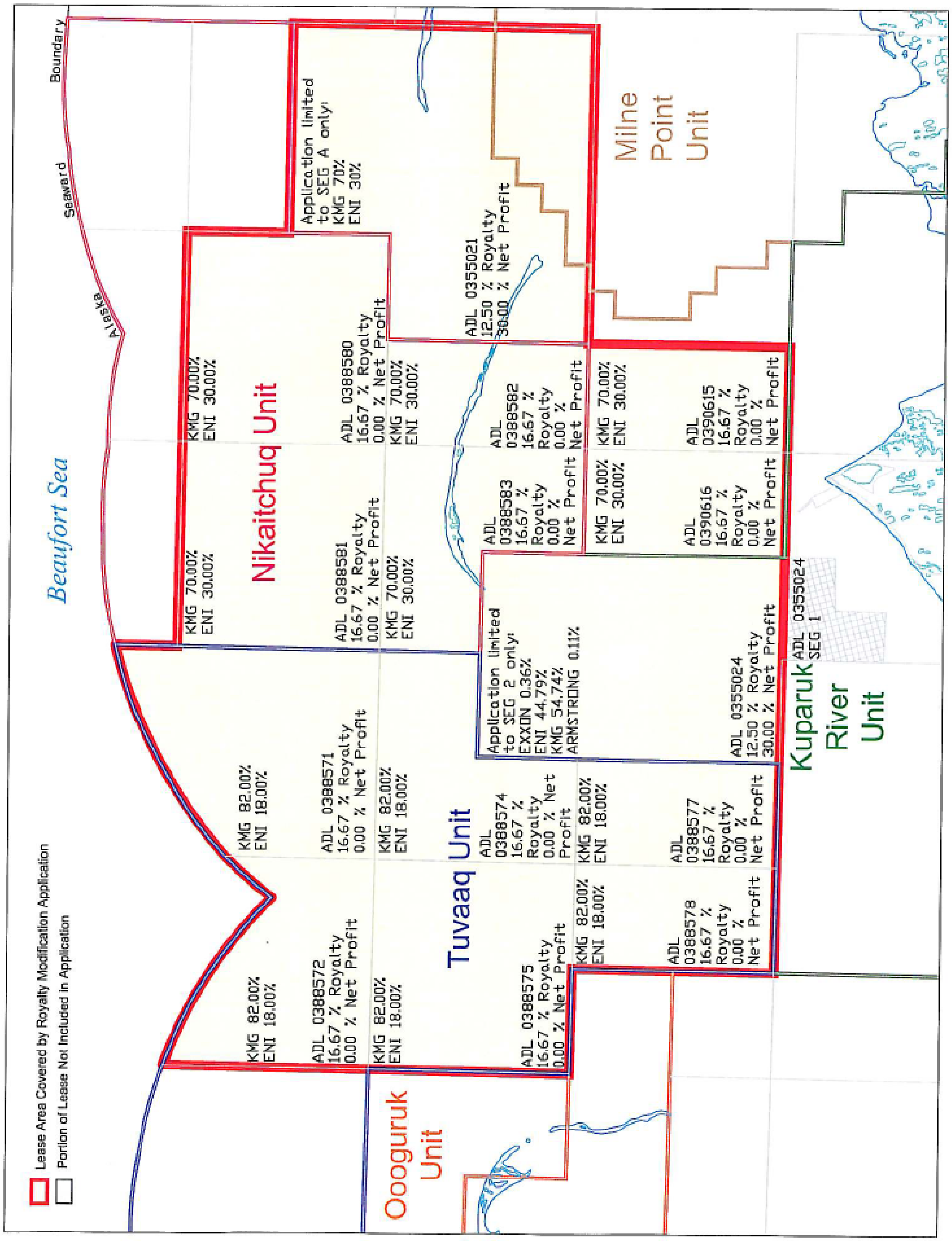
Note: Throughout this document click on the Exhibits and Figures with boxes and jump to the picture of that particular Exhibit or Figure. Click on the Figure number in the lower right hand corner and jump back to the text of the document.

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

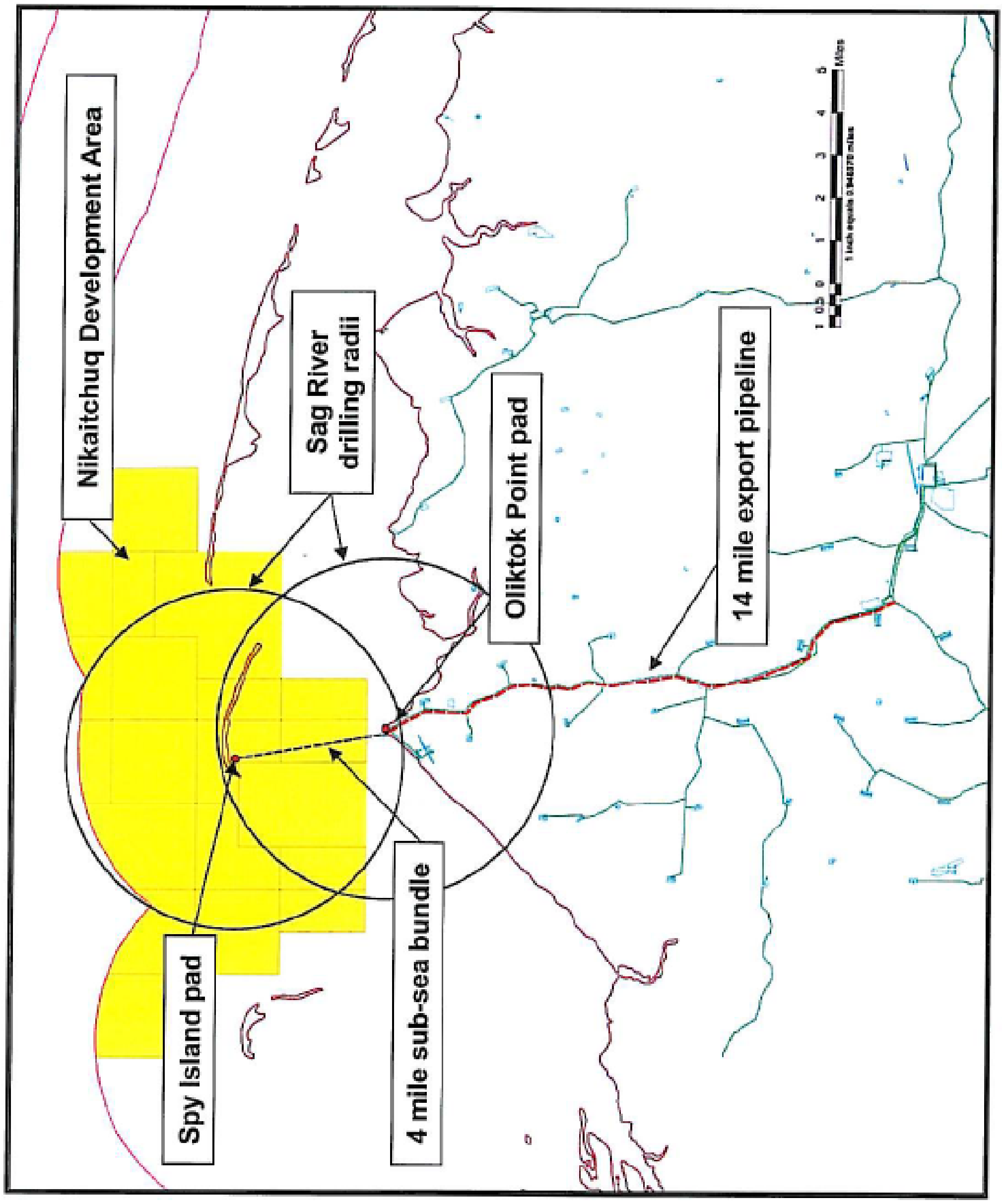
EXHIBIT B TO THE MODIFICATION OF ROYALTY APPLICATION FILED BY KERR-McGEE OIL & GAS CORPORATION ON JANUARY 11, 2006

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

ATTACHMENT 4A
NIKAITCHUQ DEVELOPMENT AREA MAP



ATTACHMENT 4B
NIKAITCHUQ PROJECT MAP



ATTACHMENT 5
Confidential Economic Analysis and Internal Decision Process

Nikaitchuq Development
Royalty Modification
Application

Preliminary 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

August 23, 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	NIkaitchuq 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