Oooguruk Development
Royalty Modification
Application

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

APPROVAL OF MODIFICATION OF ROYALTY
FOR LEASES: ADLs 355036, 355037, 355038, 355039, 389950, 389952, 389954, 389958, and 389959

February 1, 2006

Table of Contents

4. Oooguruk Unit Agreement, Exhibit B
5. Figures 2A and 2B Preliminary Participating Area & Unit Expansion Maps
6. Summary of applicant work sessions
7. ANS price forecast, Alaska State Department of Revenue
8. North Slope of Alaska Facility Sharing Study
9. Charter for Development of the Alaskan North Slope
10. 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"

    Pioneer Project Description, December 2004, and Commercial Models, February and March 2005.

    Initial Application for Royalty Modification, Pioneer, May 20, 2005

    Pioneer revised Proposal to Develop, August, 2005, and Economic Analyses, September and October, 2005

    Amended Application for Royalty Modification, Pioneer, November 1, 2005

    DNR Agenda April, 2005

    DNR summaries of NPS lease development account balances and EIC amounts, April, 2005

    DNR Flow chart of decision process metrics, summary and overview of mechanism.

    DNR Model printouts to support confidential analysis
11. Public Comments

I. BACKGROUND

On May 20, 2005, Pioneer Natural Resources Alaska Inc. (Pioneer) as operator of the Oooguruk Unit and on behalf of itself and Armstrong Alaska, Inc. (Armstrong) 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). Pioneer submitted an amended application on behalf of itself and ENI Petroleum Exploration Co. Inc. (ENI) on November 1, 2005. This Final Findings and Determination responds to the amended application and grants royalty modification to the nine leases -- ADLs 355036, 355037, 355038, 355039, 389950, 389952, 389954, 389958, and 389959 under AS 38.05.180(j).

Pioneer had applied for royalty modification on these nine leases which overlie the Nuiqsut and Kuparuk C reservoirs. It requested that the fixed royalty rates of 12.5 percent on the four Net Profit Share (NPS) leases ADLs 355036, 355037, 355038, 355039, 16.6667 percent on the other five leases, ADLs 389950, 389952, 389954, 389958, and 389959), be reduced to the minimum rate allowed, five percent, with the NPS to remain at 30 percent on the four NPS leases.

The Commissioner published the Preliminary Findings and Determination and gave public notice of a 30-day public comment period that began on December 20, 2005, and closed at 5pm January 18, 2006, with legal advertisements in the Anchorage Daily News, The Fairbanks News-Miner, The Juneau Empire, and The Arctic Sounder (Attachment 2). The Commissioner appeared before the Legislative Budget and Audit Committee on January 12, 2006, to provide a review of the Findings and Determination, the Confidential Economic Analysis, and the administrative process. 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 final and not appealable to the court.

II. SUMMARY OF PIONEER'S APPLICATION FOR ROYALTY MODIFICATION

On May 20, 2005, Pioneer, on behalf of itself and Armstrong, submitted an application to the DNR Commissioner for modification of royalty on four leases--ADLs 355036, 355037, 355038, and 355039--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) Pioneer submitted a complete application with the required $250.00 filing fee. Effective September 1, 2005, Armstrong assigned its interests in the leases to ENI and on November 1, 2005, Pioneer, on behalf of itself and ENI, submitted an amended application. The amended application requests royalty modification under AS 38.05.180(j)(1)(A) for a total of nine leases-- ADLs 355036, 355037, 355038, 355039, 389950, 389952, 389954, 389958, and 389959.

A. Lease Summary

The Division of Oil and Gas (Division) issued ADLs 355036, 355037, 355038, and 355039, 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 ten-year primary terms 12.5 percent fixed royalty rate and 30 percent NPS for the State. These four leases were committed to the Kuukpik Unit, which terminated effective June 1, 2001. Prior to lease term expiration, a well was drilled on each lease, (Attachment 3), and the wells were certified capable of producing in paying quantities, which extended the leases' primary terms indefinitely.

The Division issued ADLs 389950, 389952, 389954, 389958, and 389959, effective August 1, 2002, on Competitive Oil and Gas Lease Form No. (DOG 200004) with a 16.66667 percent fixed royalty and seven-year primary terms. Effective July 11, 2003, the leases were committed in their entirety to the newly formed Oooguruk Unit (Attachment 4), which extended the primary terms.

As a result of several assignments of working and royalty interest shares, 70 percent of the working interest of each of the subject leases is held by Pioneer and 30 percent is held by ENI. Each lease has overriding royalty interest owners. Pioneer and Armstrong negotiated a farm-in agreement with ConocoPhillips Alaska, Inc. (CPAI) early in 2004. ADLs 355036, 355037, 355038, and 355039 are vertically segmented: Pioneer and ENI own 70 percent and 30 percent, respectively, of the working interest in the upper horizon of these leases. Pioneer and ENI own 47.06 percent and 20.17 percent, respectively, of the working interest in the lower horizon of ADL 355036, and Pioneer and ENI own 39.38 percent and 16.87 percent, respectively, of the working interest in the lower horizon of ADLs 355037, 355038, and 355039.

B. Project Development History

On July 16, 2002, Armstrong submitted a Plan of Operations to drill three wells on its leases, ADLs 355036, 355037, 355038, 355039, 389950, 389952, 389954, 389958, and 389959, which the Division approved on November 19, 2002. On November 20, 2002, Pioneer and Armstrong met with the Division to discuss the technical aspects of their prospect and the process to form a new unit.

Effective December 1, 2002, Armstrong assigned Pioneer 70 percent working interest in its nine leases and named Pioneer operator of the proposed unit. Subsequently, Pioneer announced plans to drill up to three wells during the 2002-2003 winter drilling season. Pioneer's primary target was the Kuparuk C sands, which had been encountered in the nearby Kuparuk River Unit to the southeast, although prospective intervals to be tested by this exploration program included, but were not limited to, the Cretaceous Middle Brookian, Cretaceous Torok, Kuparuk A, Kuparuk C, and the Jurassic Nuiqsut/Nechelik.

Pioneer submitted an application to form the Oooguruk Unit on January 31, 2003. The Division approved the formation of the Oooguruk Unit effective July 11, 2003.

On February 24, 2003, Pioneer spud its first exploration well in Alaska, the Ivik 1 well. The three exploratory wells (Oooguruk 1, Ivik 1, and Natchiq 1) drilled by Pioneer within the initial Oooguuk Unit Area satisfied the Unit Plan of Exploration. In January 2004, Pioneer and Armstrong obtained access to additional geologic and well data through the farm-in agreement with CPAI. Pioneer completed a thorough review of the new data and on May 20, 2005, submitted a formal application for royalty modification on ADLs 355036, 355037, 355038, and 355039. Pioneer planned to file a unit expansion application with the Division on June 15, 2005.

On August 17, 2005, Pioneer submitted a copy of a written Proposal to Develop to the Division. Under the Oooguruk Unit Operating Agreement, the Operator is required to submit a formal written Proposal to Develop to the Working Interest Owners (WIO) of the Unit. Pioneer continued refining its geologic interpretation and economic model for the development and submitted an amended application for royalty modification on November 1, 2005. Pioneer is currently working with the Division to develop a complete unit expansion application. Pioneer intends to apply to establish two participating areas within the unit (Figures 2A and 2B, Attachment 5).

C. Royalty Modification Request

The amended application requests that the royalty rate for ADLs 355036, 355037, 355038, and 355039 be modified from a fixed royalty rate of 12.5 percent with a 30 percent net profit share to the State to a five percent royalty rate and a 30 percent NPS to the State and that the royalty rate for ADLs 389950, 389952, 389954, 389958, and 389959 be modified from a fixed royalty rate of 16.6667 percent to a fixed royalty rate of five percent. The application also requests that "the account balance for payback determination of the NPSL be set at $80,000,000, which is the sum of all monies that have been spent to date within the proposed Oooguruk Unit." Pioneer also requests "Oooguruk [be] treated as separate and distinct from KPA (Kuparuk Participating Area) for ELF factor calculation, resulting in a severance tax that is effectively zero."

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 royalty modification may not be granted for the field or pool if the royalty modification would result in 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.
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. 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. FINAL ROYALTY MODIFICATION REQUIREMENTS AND TERMS

A. Royalty Modification Requirements

1. Pioneer's application for royalty modification on ADLs 355036, 355037, 355038, 355039, 389950, 389952, 389954, 389958, and 389959 meets the requirements set out in AS 38.05.180(j)(1)(A). Pioneer 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 Cretaceous Kuparuk C and Jurassic Nuiqsut pools in the Oooguruk field have been sufficiently delineated to the satisfaction of the Commissioner for the purpose of granting royalty modification; the pools have not previously produced oil or gas for sale; and oil or gas production from the pools would not otherwise be economically feasible.

3. **3.** Pioneer has made a clear and convincing showing that a royalty modification meets the requirements of AS 38.05.180(j)(1)(A), and is in the best interests of the State.

B. Royalty Modification Terms

1. **The** Oooguruk Development royalty relief mechanism will be implemented as follows:
   a. A five percent royalty rate will be in effect for production from the delineated pools until NPS payments first become due to the State from ADL 355036 as calculated under 11 AAC 83.201 – 11 AAC 83.295. The first month following the month when NPS payments first become due to the State is the month when a four-year royalty modification phase-out commences for all nine leases subject to the royalty modification.
   b. At the beginning of each of the four 12-month periods following the month when NPS payments first become due to the State from ADL 355036 the royalty rate for each of the nine leases will be increased by 1.875 percent, resulting in a cumulative increase of 7.5 percent, (four years X 1.875 percent/year). At the beginning of the fourth 12-month period after NPS payments first become due to the State from ADL 355036, the fixed royalty rate for ADLs 355036, 355037, 355038, and 355039 will be restored to 12.5 percent and the NPS rate will remain at 30 percent. At the beginning of the fourth 12-month period after NPS payments first become due to the State from ADL 355036, the royalty rate for ADLs 389950, 389952, 389954, 389958, and 389959 will be immediately restored to a full 16.6667 percent.
   c. No additional recapture mechanism beyond the net profit share is included in the royalty modification mechanism.

2. The Oooguruk project as set out in the amended application must be sanctioned, (in-house approval and funding), by Pioneer by December 31, 2007. If Pioneer does not provide project sanction documents and AFEs to DNR by December 31, 2007, this royalty relief is rescinded.

3. If Oooguruk project "facilities capex" (including, but not limited to island construction, surface equipment, and flowline bundle.), costs less than 75 percent of the amount set out in the amended application, $246 million, this royalty relief is rescinded.

4. The NPS lease regulations set out in 11 AAC 83.201 – 11 AAC 83.295 remain in full force and effect. However, Pioneer's request that the current unaudited NPS

lease balance of $80,000,000.00 as of January 1, 2005, be deemed true and correct and not be subject to future adjustment resulting from audit, is approved.

5. The $80,000,000.00 NPS lease balance will be allocated to the NPS leases (ADLs 355036, 355037, 355038, and 355039) pursuant to the final participating area redetermination.

6. Pioneer requested that "Oooguruk [be] treated as separate and distinct from KPA (Kuparuk Participating Area) for ELF factor calculation, resulting in a severance tax that is effectively zero." Severance tax issues are within the jurisdiction of the Department of Revenue and not affected by this Findings and Determination.

7. This royalty modification is not assignable without prior written approval of the Commissioner. This modification is based on the financial and technical data supplied to the Commissioner in the amended application and on Pioneer's unique showing that production would not be economical from these Oooguruk pools with the modification approved here. The Commissioner will not approve a transfer of the royalty modification unless the assignee also makes a clear and convincing showing that the modification meets the requirements of AS 38.05.180(j)(1) and is in the best interests of the State.

V. DISCUSSION OF ROYALTY MODIFICATION CRITERIA

A. Leases are eligible for consideration.

The leases meet the criteria for consideration, four of the leases proposed for royalty modification are committed to the Oooguruk Unit and five are individual 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 AS 38.05.180(j)(1)(A)(i). Here, the potentially commercially recoverable reserves reside in the Cretaceous (Hauterivian) Kuparuk C sandstone and the Jurassic Nuiqsut sandstone. My review of the exploration and drilling history of the area shows that these Kuparuk and Nuiqsut reservoirs have been sufficiently delineated. Explorers have drilled and found evidence of oil deposits near the Oooguruk Unit in early exploration wells.

Subsequent explorers have drilled eight wells in the Unit. The State has certified these wells as being capable of producing oil in commercial quantities. Seismic work has further defined the pools, though much uncertainty remains. Finally, Pioneer's evaluation of its recent drilling work supports a possibility that the Nuiqsut and Kuparuk reservoirs could yield 18 to 20 thousand barrels of oil per day (BOPD).

2. Exploration History of the Area

Two exploration wells lie within a mile of the Oooguruk Unit. The Unocal East Harrison Bay State 1 well lies due east in the northwest corner of the Kuparuk River Unit (KRU). The well was drilled in February 1977 as a straight hole to a measured depth (md) of 9,809 feet, bottoming in argillite basement. The well logs indicate the presence of about 15 feet of oil-bearing Kuparuk C sandstone around 6,171' md (around -6,138' true vertical depth subsea (tvdss)) that appears siderite cemented in the upper half of the section, based on the density log. The Jurassic section is present around 6,400' to 7,958' md (-6,367' to -7,925' tvdss) and appears to contain predominantly interbedded shale, siltstone and minor thin silty sandstone sequences on logs.

The second well drilled within a mile of the Oooguruk Unit, the ARCO KRU 3W-07 well, was drilled in March 1993 just south of the Oooguruk Unit. Well logs indicate the presence of 15 feet of oil-filled Kuparuk C sandstone at a depth around 10,127' md (-5,974' tvdss) that also appears to contain some siderite cement near the top of the interval, based on the density logs. The well was plugged and abandoned on April 12, 1993.

Another non-certified well was drilled within the Oooguruk Unit. The ARCO Kalubik 3 well, drilled in February 1998, lies in the northwest corner of the Oooguruk Unit. The well bottomed in Jurassic age rocks at a measured depth of 7,000 feet. The well encountered a 25-foot thick Kuparuk C sandstone around 6,330' md (-6,247' tvdss) that appears to be oil-bearing, but siderite cemented-in the upper 10 feet of the interval. Based on well logs, the top of the Jurassic section appears present just below the Lower Cretaceous Unconformity (LCU) around 6,355' md (-6,272' tvdss). Overall the Jurassic interval appears dominated by thin interbedded shale and siltstone sequences. An eight foot silty sand (interpreted to be the Nechelik Sandstone) is present at around 6,565' md (-6,483' tvdss). The well was plugged and abandoned on March 6, 1998.

3. Certified Wells in the Vicinity

Six of the eight certified wells drilled in the vicinity lie within the proposed Oooguruk Unit expansion acreage. Five of the certified wells lie on NPS leases ADL 355036, 355037, 355038, and 355039 for which Pioneer requested royalty modification. The eight wells that have been certified by the state as capable of production in paying quantities are: Exxon Thetis Island 1, in the northeast part of the Unit; ARCO Kalubik 1; and four Colville Delta wells (Texaco Colville 1, 1A, 2, and 3) that lie on the four NPS tracts. The other two certified wells, outside and to the west of the Oooguruk Unit, are the Kuukpik 3 (approximately two and one-half miles) and the Amerada Hess Corporation (AHC) Colville 25-13-6 (approximately a quarter of a mile).

The Exxon Thetis Island 1 well was spud on March 6, 1993, and plugged and abandoned on April 28, 1993. A combined co-mingled drill stem test was conducted in two intervals: an eight foot Kuparuk C sandstone present around 6,356' to 6,364' md (-6,302' to -6,310' tvdss) and a Jurassic sandstone, interpreted as Nuiqsut, from 6,404' to 6,460' md (-6,370' to -6,426' tvdss). Following acid treatment, the combined intervals flowed oil at an average rate of 154 BOPD of 24.8º API oil. Exxon also tested a sandstone within the Seabee formation at 5,576' to 5,633' md (-5,542' to -5,999' tvdss) 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 well was spud on March 5, 1992, and plugged and abandoned on May 1, 1992. A drill stem test was conducted in the Kuparuk C sandstone from 6,085' to 6,120' md (-6,048' to -6,083' tvdss) and produced oil at a rate of 1,200 BOPD with a 450 GOR and zero percent water cut. Two other intervals were tested in the well. An upper Cretaceous sandstone (5,050' to 5,250' md) (-5,013' to -5,213' tvdss) produced oil at an average calculated rate of 10 BOPD. The Jurassic Nuiqsut sandstone was also tested from 6,385' to 6,445' md (-6,348' to -6,408' tvdss) and produced oil at a calculated rate of 336 BOPD of 23º API oil and a GOR of 232 scf/stb. ARCO applied for well certification for the Kalubik 1 well on September 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 wells, and the AHC Colville 25-13-6 well were certified by the state as capable of production in paying quantities on October 14, 1991, for the Jurassic Nuiqsut sandstone. In the Colville Delta 3 well, Texaco tested a Torok sandstone (5,120' to 5,183' md) (-5,087' to -5,150' tvdss) that recovered 841 barrels of 24 º API gravity oil and diesel, 2 barrels of water, and 508 thousand cubic feet of gas 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 January 12, 1998.

4. Seismic Information

The primary seismic data coverage the Division used to evaluate the Oooguruk Unit is been the WBA97 3D. This 3D survey was acquired by Western Geophysical for ARCO Alaska in 1997 (MLUP 96-009-01) and was licensed to Pioneer.

Although this 3D dataset is adequate for assessing both the distribution and potential thickness of the Kuparuk Formation for the area, the Jurassic Nuiqsut sands are, so far, poorly expressed on any available seismic dataset. This is principally because the acoustic impedance contrasts between sand-silt-shale intervals for the Jurassic section are very small, resulting in a zone of weak reflectivity for the entire interval. Some effort could be made to map the top of the Nuiqsut sands. However, the available seismic data make it impossible to reliably predict either the thickness or potential quality of the reservoir with much accuracy. An additional complication for this area is the Oooguruk

Unit's location in the onshore-offshore transition zone. Because of the rapid lateral changes in the shallow permafrost section that occur in the transition zone, depth maps for the deeper section created from seismic data can contain significant errors where well control is relatively sparse. In light of these concerns about the inadequacy of the seismic data related to the Nuiqsut accumulation and the absence of long-term production tests, we question whether the Nuiqsut reservoir is sufficiently delineated to allow determination of single point estimates of in-place or recoverable hydrocarbons. The limited ability of the seismic to describe the Nuiqsut accumulation highlights the risks associated with Pioneer's proposed development.

5. Results of Pioneer's 2003 Winter Drilling Program

Pioneer drilled three exploration wells during the winter of 2003 from ice islands in the shallow waters of the Beaufort Sea, northwest of the KRU. The three wells have Inupiat names: Ivik (walrus), Oooguruk (bearded seal) and Natchiq (seal). The Oooguruk well, a vertical hole, was completed March 29, 2003, to a depth of 6,900 feet. The Natchiq well was completed March 31, 2003, to a depth of 7,500' md (6,740' tvdss). The Ivik well was completed April 9, 2003, to a depth of 6,943' md (6,942' tvdss). (PNA, May 18, 2003).

Although Pioneer's main objective was originally the Kuparuk C sands, the company did not find commercial quantities of oil in the Kuparuk C sandstone in the three wells. Pioneer reported that: "Although all three of the wells found the sands filled with oil, they were too thin to be considered commercial . ." (PNA, March 31, 2003). However, Pioneer reported that it had encountered two "thick, oil-bearing, Jurassic-aged sands, a secondary target . ." (PNA, April 13, 2003) "very similar in geologic age, permeability, and porosity to those in the prolific, onshore Alpine field to the southwest" of the Oooguruk Unit (PNA, May 4, 2003). Because of the similarity of all three northwest Kuparuk wells drilled, Pioneer tested only the Ivik 1 well. Pioneer fractured the wellbore and the well flowed at an initial rate of approximately 1,300 BOPD. Pioneer spokeswoman Susan Spratlen summed up their concerns about the commerciality of the Oooguruk Unit: "The issue is determining the permeability, how much oil there is and what the recovery factor will be." (PNA April 6, 2003). Based on Pioneer's evaluation of the 2003 drilling results and well test in the Jurassic sands, coupled with the addition of the four Colville Delta leases acquired from CPAI that have viable Kuparuk C oil potential, Pioneer determined that the project could be commercially viable with royalty relief. Pioneer has publicly estimated that peak production for the Oooguruk project is in the range of 18,000 to 20,000 BOPD from both the Kuparuk and Nuiqsut formations combined.

6. Conclusion

The Oooguruk development area for the Kuparuk Formation has been sufficiently delineated by a combination of well, seismic, and structural control. The Kuparuk accumulation is limited to the area of sandstone deposition on the down thrown side of the Kalubik fault that is defined by seismic data and confirmed with well control. The thickness of the Kuparuk C sandstone in the area is below definitive seismic resolution. Seismic total amplitude analysis does identify areas where the Kuparuk formation is likely to be present even when the Kuparuk interval total thickness is less than 70 feet. Reservoir parameters and productivity of the Kuparuk Formation is well known from North Slope fields where the Kuparuk sandstone is economically produced including the Kuparuk River Unit, Milne Point, Pt. McIntyre, Niakuk, Prudhoe Bay (Midnight Sun, Aurora and Borealis participating areas), and most recently in the Nanuq and Fiord pool satellites of the Colville River Unit. The size and extent of the Kuparuk accumulation in the Oooguruk Unit has been sufficiently delineated.

The extent to which the Jurassic Nuiqsut formation has been delineated remains problematic due to the lack of singular point estimates. ADL 355036 contains the Kalubik 1 well and the bulk of the Kuparuk C sandstone pool reserves also contains the best delineated Nuiqsut sandstone. Of the five certified wells that lie on the four NPS leases (ADLs 355036, 355037, 350398, and 350399) the proposed Nuiqsut pool development area contains two of the certified wells: Kalubik 1 (test rate 379 bpd, 20° API) and Colville Delta 2 (final test rate 485 bpd average for 94 hours, 24° API). Colville Delta 2 was tested the longest of all the Colville Delta wells and the operator noted that the well experienced a "rapid decline." The western edge of the proposed Nuiqsut development area is defined by seismic attribute analysis and well control. Five certified wells are distributed outside of the western edge of the proposed development area. The five certified wells include: Colville Delta 1A (test rate 273 bpd average for 39 hours, 25° API); Colville Delta 3 (test rate 290 bpd average for 100 hours, 27° API); Amerada Hess Colville Delta 25-1 (final test rate 104 bpd average for 35 hours, 26° API); and ARCO Kuukpik 3 (test rate 77 bpd average in 25 hours, 25° API). Well data from the ARCO Kalubik 3 well limits the Jurassic delineation to the north. Based on well logs, the well encountered oil bearing Kuparuk C sandstone in the upper 5 feet of the 25 foot interval. The Nuiqsut interval appears thin (approximately 35 to 40 feet of silty sandstone and the top of the formation appears to have been truncated by the LCU. The Natchiq 1 well appears to consist predominantly of clay and silt on well logs, thus defining the extent of the Nuiqsut accumulation to the east. The log character and test results from the five certified wells to the west and southwest of the Nuiqsut development area and the log character of the Kalubik 3 well to the north and the Natchiq 1 well to the east indicate that the Nuiqsut is thick but contains a high percentage of clay and siltstone. Test results provide lingering questions surrounding permeability. All successful tests in the Nuiqsut Formation all required stimulation, usually a fracture treatment and several required acid to clean up mud damage.

To the northeast of the proposed Nuiqsut development lies the Ivik 1 exploration well that tested the Nuiqsut at a rate of 600 to 1,300 BOPD of 20º API oil (total test time 95 hours). Depositional trends within the Nuiqsut interval suggest the possibility that the Nuiqsut is cleaner (with better developed sands) near the Ivik 1 and Oooguruk 1 wells (Oooguruk 1 was not tested). The Exxon Thetis Island 1 well northeast of Oooguruk Unit did test the Kuparuk C and Nuiqsut formations in a combined test that flowed at a rate of 154 BOPD of 24.7 API oil after an acid stimulation. The lack of any long term unstimulated test in the Nuiqsut formation in the Oooguruk Unit area or elsewhere on the

North Slope provides uncertainty of future Nuiqsut formation productivity. Given the thickness and distribution of the Nuiqsut sandstone, there is considerable up-side, as modeled by DNR, if the Nuiqsut becomes more sand-prone, the permeability increases, and the API gravity increases.

In conclusion, the Kuparuk Formation is adequately delineated in the Oooguruk area and is of limited areal extent. The accumulation is limited to the area along the downthrown side of the Kalubik fault. The Nuiqsut formation has been adequately delineated by well control in the four NPS leases and surrounding acreage and to a lesser extent to the northeast in the area around the Ivik 1 and Oooguruk 1 wells. The characteristic low porosity, permeability, and relatively low gravity 20-25° API combine to make it difficult to predict Nuiqsut oil productivity from the wells drilled to date and establish an adequate delineation of the Nuiqsut reservoir northeast of the Ivik 1 and Oooguruk 1 wells. Total amplitude seismic attribute analysis in the Jurassic window does not demonstrate possible sand-prone areas as well as in the Kuparuk window. More well control and long term production testing is required to further delineate the Nuiqsut formation.

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 or gas production would not otherwise be economically feasible.

Pioneer 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 Pioneer's geologic, engineering and cost data. These documents are included and discussed in detail in the Confidential Economic Analysis and Internal Decision Process, (Attachment 10).

To obtain royalty relief the applicant must show by clear and convincing evidence that without royalty modification the project is not economically feasible. Pioneer has represented to the State that it would not do the project without royalty relief. Other companies that have owned leases in the area and explored there have not developed this prospect. Finally, and most convincingly, Pioneer has shared data with the State showing a project that without royalty modification fails to meet minimal economic targets.

Pioneer represented to the State that the Oooguruk development project was "extremely marginal, and has considerable risk of low investor returns" without royalty relief. It made the representation after modeling and studying the reservoir and estimated costs. Pioneer developed an economic model for the project that considered the field as an aggregate of production from both the Nuiqsut sand and the Kuparuk C interval. Although Pioneer identified a suitable quantity of original oil in place (OOIP) within the Nuiqsut sand, the recovery rate is predicted to be low. Furthermore, the Nuiqsut reservoir may present significant challenges to achieve even a modest recovery rate. A full assessment of Nuiqsut reservoir performance will not be possible until after substantially all of the field infrastructure is in place, (gravel island, sub-sea pipelines, and facilities). The Kuparuk C interval contains a far lesser OOIP, but is characterized by a good recovery rate.

As its understanding of the reservoir characteristics and rock and fluid properties increased, Pioneer examined the application of enhanced oil recovery (EOR) technology, which would cost more than the waterflood project initially planned. With detailed analysis of the higher costs to apply EOR, Pioneer found that the production levels (and thus revenue) gained by EOR would still not result in economically feasible production. Pioneer's representatives said that they could not receive in-house approval and funding, ("sanctioning"), to pursue the production of the Oooguruk development area, unless the project economics improved. Pioneer proposed that royalty modification would improve revenues sufficiently to result in an economically feasible project.

The Oooguruk prospect remains undeveloped despite other companies' interest. ARCO and Texaco previously identified the Nuiqsut reservoir and determined it to be uneconomic to develop. These companies drilled wells and found producible hydrocarbons sufficient to meet the standards for certification as capable of producing in paying quantities using the paying quantities definition in 11 AAC 83.105. However, due to insufficient project economics the wells were shut-in and abandoned.

Pioneer shared its economic model of the proposed Oooguruk development with DNR. Independently, DNR also developed its own economic model of the Oooguruk development based on the confidential reservoir and cost information provided by Pioneer. Using both models, the State has examined the project's financial metrics including Net Present Value (NPV), rates of return, Expected Mean Value (EMV)[1], and years to payout under a wide variety of oil price assumptions. The methodology used by DNR is explained in Section E.

This examination reveals a stressed project at all but high prices. Without royalty modification the ANS price must average more than $40.00 per barrel before the EMV, discounted at 10 percent, turns positive. This indicator should be considered in light of the United States Department of the Interior Minerals Management Service (MMS) royalty relief regulations that require that the project fail to make between a 10 percent and 15 percent rate of return using projected prices before being considered for royalty relief[2].

In addition to demonstrating that the project is not economically feasible without royalty modification, the project should be economically feasible with royalty modification. Pioneer has stated that they will do the project if it obtains full royalty modification (a royalty rate of five percent for the life of the project). The table below shows how rates

[1] Expected Mean Value is the probability weighted average of all possible NPVs calculated in each Monte Carlo model outcome.

[2] See MMS's Appendix I to NTL No. 2002-N02, Guidelines for the Application, Review, Approval, and Administration of the Deep Water Royalty Relief Program for Pre-Act leases and post-2000 leases, February 2002, ("Guidelines") at pg. 14.

of return and NPVs are affected by royalty modification: royalty modification increases the rate of return for the project by over two percent. The modeled impact of royalty modification supports Pioneer's assertion that royalty relief makes a difference.

As discussed further in Section E of this Findings and Determination, limiting royalty relief to the period before NPSL payout followed by a four-year period when the five percent royalty rate will "ramp-up" to the original lease royalty rate, will lower Oooguruk project returns only marginally. The impact of the State's decision is shown in Table 1.

E. Economic Analysis

DNR studied the information submitted by Pioneer and designed and built its own in-house economic model for Oooguruk development (DNR Model) to independently assess the economic effects of a royalty modification for both Pioneer and the State of Alaska. Pioneer shared with the State portions of its proprietary economic model but, in the end, the State chose to use its own model that incorporated many input assumptions provided by Pioneer.

Table 1: Increase to Pioneer's Net Present Values (NPV) and Internal Rate of Return Caused by Royalty Relief

ANS Price	Pioneer Proposal		DNR's Decision	
	NPV(10) Δ($MM)	IRR Δ(%)	NPV (10) Δ($MM)	IRR Δ(%)
$20.00	17	2.0%	17	2.0%
$30.00	29	1.9%	27	1.7%
$40.00	28	1.7%	20	1.3%
$50.00	36	2.0%	19	1.3%
$60.00	44	2.2%	23	1.5%

DNR closely examined the assumptions and methods currently in use by the 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). The applicant submits inputs for the model that define the project economics. MMS then independently analyzes the inputs and determines whether royalty relief is warranted. The royalty modification terms used by MMS provide for a sliding scale based on oil price and termination of royalty modification based on a significant change in project costs or production. Under the MMS system, decreased revenues due to royalty modification are in part recaptured through Federal Income Tax.

Where possible DNR adopted an approach similar to that of the MMS by developing an independent model and implementing a decision path using metrics from the model. DNR used the Net Profit Share lease accounting provisions, as set out in 11 AAC 83.210

– 11 AAC 83.295, which incorporate project costs, price, and production to determine the payout date. The NPS payout date will trigger the end of full royalty modification. Like MMS, DNR implemented a provision to rescind royalty modification if the project as built differs significantly in scope from the project description provided by the applicant. Unlike the MMS, the State does not have an opportunity to recapture decreased revenues due to royalty modification through increased tax revenues.[3] Additionally, the State implemented a four-year ramp-up period to transition from modified royalty to the full royalty rate.

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 Oooguruk development over at least a 25-year time horizon. The DNR Model incorporates the State and Federal tax and royalty fiscal system, as well as other important commercial relationships. 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, profit to investment ratio, NPV, EMV, rate of return on investment and profitability ratio, 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 @Risk proprietary software 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 (X, X1, X2) 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, in other words, the low case. A P50 indicates that 50 percent of the results are at least equal to X1, the median case. The P10 case is the high side case. Here the results fall in the X2 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.

[3] In fact any benefit generated by the State by granting royalty reduction to the Oooguruk lessees is shared with the Federal government in potentially increased federal income taxes payable by the lessees.

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, which is also based on a probability model, determines the revenue stream. The risk weighted cost profiles are then matched to the revenue stream. 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 inflation, 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 Pioneer models did not produce identical results. The numerous work sessions and presentations (Attachment 6) served to resolve differences in modeling between DNR and Pioneer; and the resulting DNR model reflects a substantial agreement between DNR and Pioneer on the modeling assumptions, methodologies, and results. They differ primarily in that the DNR Model includes price forecasts that accommodate the potential price volatility observed in the recent past.

DNR has received three sets of increasingly detailed input data from Pioneer. With each submission, Pioneer has narrowed the range of possible outcomes for resource, production, and cost. This reflects the increased level of knowledge that Pioneer 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 Oooguruk development, under the existing royalty rates as specified by the individual leases, is not economically feasible using the ANS price forecast from DOR Alaska Department of Revenue (DOR) as reported in the 2005 Revenue Source Book, (Attachment 7).

Once DNR has determined that, when evaluated on a stand-alone basis without any royalty modification, the project is not economic, DNR will determine whether the project is economically feasible with royalty modification. DNR cannot grant royalty modification for projects that meet the economic test on their own without royalty modification. Similarly, DNR will not grant royalty modification for projects that, even with maximum royalty modification, are still not economically feasible. DNR has concluded that this project qualifies as an economically challenged development of marginal pools, which merits royalty modification. And, DNR has concluded that the project is feasible with royalty modification.

Under AS 38.05.180(j)(3) the State must tailor its royalty relief to be sensitive to certain relevant factors including oil prices, costs, and production levels. The simplest and most reasonable way to do this is to use the NPS lease accounting provisions. In Oooguruk, four of the nine subject leases are NPS leases. As modeled, 80 percent of potential production is on these leases. This creates a unique situation in that the NPS lease terms create a framework by which the State can share in the success of the project once the project reaches payout. Since the development area is comprised of a high proportion of NPS leases, the State has the opportunity to receive a higher proportion of total revenue than would be the case if all the leases in the development stipulated a fixed royalty rate.

The NPS leases yield 12.5 percent royalty, the State receives 12.5 percent of production in value or in kind. Once the leases reach payout, the State also receives a 30 percent share of net profits (as defined in the lease and governing regulations). NPS leases have a complex accounting methodology to determine payout. As set out in 11 AAC 83.201 – 11 AAC 83.295, three accounts are established: the Production Revenue Account, the Development Account and the Net Profit Payment Account. Any month where the balance in the Production Revenue Account exceeds the balance in the Development Account results in a credit to the Net Profit Payment Account. When the lease moves into "payout" the State receives the net profit share rate. However, the project will not reach payout until a point at which the production volumes have declined from peak rate.

The DNR modeling shows the NPS payout under DNR's proposed royalty modification will occur anywhere from eight to 28 years after production start-up, earlier at high oil prices and later at low prices. NPS payout was estimated to occur four to 10 years sooner with royalty modification than without royalty modification.

This tie-in to NPS leases enhances the State's ability to monitor the financial progress of the project, in effect verifying the modeling results and the basis for this determination. NPS auditing provides the State an existing process by which to monitor the costs and revenues of the project and thus to implement the terms of royalty modification, including the royalty ramp-up. There is no increased administrative burden to the State or the lessees to monitor the accounts as the NPS lease terms already establish the audit requirements. Also, as shown above, the NPS payout timeline that triggers the royalty rate ramp-up have a modest impact on project returns.

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. THE ROYALTY MODIFICATION IS IN THE BEST INTERESTS OF THE STATE.

A. Impact to State Revenue

Revenue to the State from oil and gas production derives from Severance Tax, (limited by ELF), Property Tax (Ad Valorem), Corporate Income Tax (maximum rate of 9.4 percent), Production Tax Surcharge for Hazardous Spills, NPS, and Royalty Revenue.

When production occurs, the State receives a share of the production. DNR's analysis of the economics of Pioneer's project indicates that without modification of the royalty rate, the project economics would not provide sufficient return for Pioneer to pursue the development. With royalty modification, the project economics improve, which should enable Pioneer to develop the project and the State to receive revenues from Severance Tax, Property Tax, Corporate Income Tax, Hazard Surcharge, NPS and Royalty.

The Table 2 summarizes the impact on State revenue with and without royalty modification for the Oooguruk development. This table shows that the NPV of royalty revenues are $90,000,000.00 lower under the terms of this royalty modification decision, assuming the price as indicated. However, over the life of the project the State should see increases in State income tax and NPS payments under lower royalty rates so that in total the State's total revenue stream is estimated to be $68,000,000.00 lower under this decision.

Table 2: State Revenue Streams

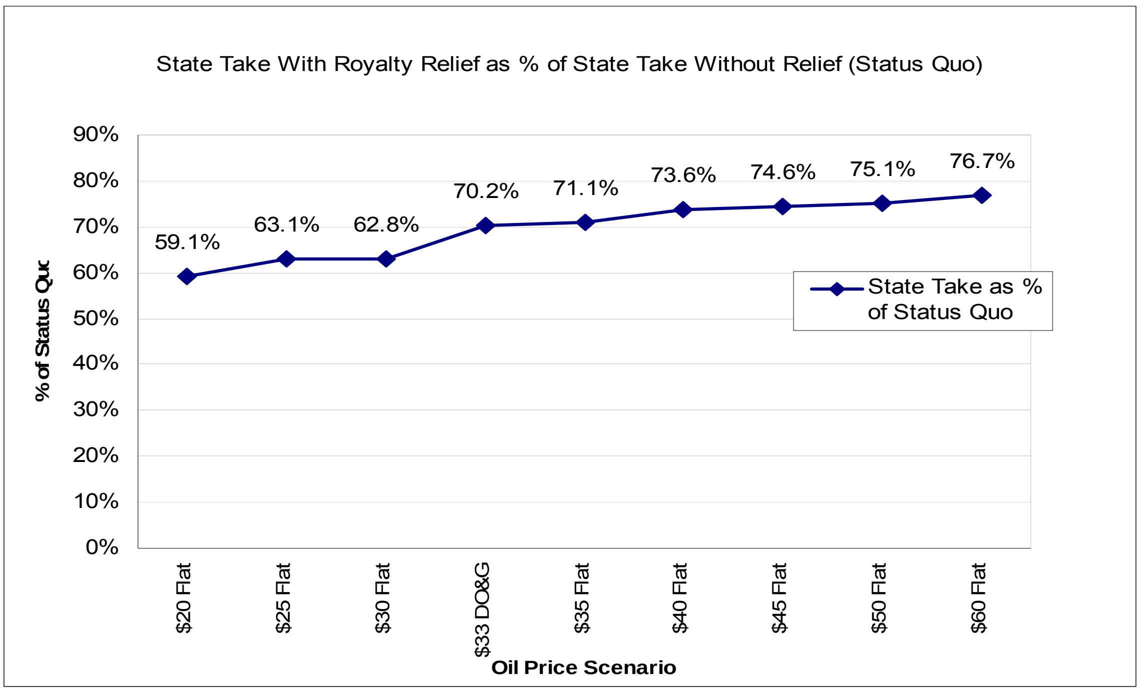
At $33 ANS WC, NPV(5)	***Without* Royalty Modification** ($ MM)	***With* Royalty Modification** ($ MM)
Royalties	144	54
Property Tax	52	52
Severance Tax	0	0
Hazard Conservation Tax	1	1
State Income Tax	22	28
Net-Profit-Share Payments	10	26
Total	228	160

Four of the leases (ADLs 3550036, 355037, 355038, and 355039) are held beyond their primary terms by wells certified capable of producing in paying quantities. If Pioneer does not develop and produce the leases, the leases may not immediately terminate and would not necessarily be available soon for a future sale. Therefore, DNR did not assume it would forego future bonus bids in the event that royalty modification was not granted.

A comparison of the Oooguruk development project using the State's model without royalty relief and with royalty relief as set out in this decision demonstrates that the royalty relief provision makes the State revenue stream less regressive. (see graph below). At low oil prices ($20.00/bbl.) the relief provisions proposed would lower the State revenue stream, including royalties, NPS payments, and taxes, by about 40 percent. Under high oil prices ($60.00/bbl.) the same relief provisions as proposed would lower the State revenue stream by about 23 percent. Thus at very high oil prices we expect to get a revenue stream that is closer to the status quo than under low oil price scenarios.

Granting of royalty modification could result in both short-term and long-term economic benefits to the State because it will enable Pioneer to pursue an otherwise uneconomic project. The additional capital funds invested in the State's economy will generate increased economic activity. The additional assessment of the hydrocarbon potential of the leases will create jobs and in-state economic activity in the short-term and, if the development activity is successful, the State will enjoy royalty and tax revenues as well as employment opportunities over the long-term.

The State's analysis of royalty relief for the Oooguruk development shows that using the ramp-up provision will result in the Working Interest Owners gaining an additional net present value of $5,000,000.00 over the life of the project, discounted at 10 percent, (see Table 3 below). This gain is $21,000,000.00 in undiscounted dollars. By implementing the ramp-up provision the State of Alaska gives up a net present value of $9,000,000.00 over the life of the project, discounted at 5 percent.



Graph of the "State Take":
"State Take" with royalty relief (as proposed) as a percent of the "State Take" without royalty relief (status quo) under a range of oil price scenarios.

Table 3	WIO NPV (10)	WIO Undisc. CF	State Rev. NPV (5)
Difference (w/ramp-up minus without)	$5MM	$21MM	($9MM)

Table 3:
Table 3 showing change in cash flows between royalty relief *with* a four-year ramp-up to royalty relief *without* a four-year ramp-up. Data are for the WIO discounted at 10 percent and the State of Alaska discounted at 5 percent.

B. Use of Infrastructure: Facility Sharing

This is the first occasion in the history of North Slope development that processing facilities will be shared by an independent producer. Pioneer intends to ship its production by pipeline to the KRU processing centers and pay fees to the owners, (BP, ConocoPhillips, and others), for the use of the facilities. The complex fee structure is outlined in detail in the North Slope of Alaska Facility Sharing Study, (Attachment 8). DNR modeled the facility sharing fees for Oooguruk production based on Pioneer's assessment of costs in the amended application. Actual fees will be compared over time through the NPS accounting provisions. The oil will be processed at the facilities in order to meet specifications required for shipment to market by TAPS.

Granting royalty modification and enabling Pioneer to develop the Oooguruk development area provides an opportunity for the owners of the KRU to achieve the goals set out in the Charter for Development of the Alaskan North Slope. On December 2, 1999, the State of Alaska, BP and ARCO signed the Charter for Development of the Alaskan North Slope (Attachment 9) in response to the proposed merger of BP and ARCO. The State recognized that the merger presented risk to the State because it would lose a certain amount of competition, diversity and balance in the exploration, development and production of North Slope resources, and the varied contributions of a leading corporate citizen. Item F of the Charter describes the goals of the State in promoting and achieving facility sharing.

C. Environmental, Social and Cultural Impacts

DNR develops lease stipulations through the lease sale process to mitigate the potential environmental, social and cultural impacts from oil and gas activity. The leases that are proposed to be granted royalty modification contain many stipulations designed to protect the environment and address any outstanding concerns regarding impacts to the area's fish and wildlife species and to habitat and subsistence activities. They address the protection of primary waterfowl areas, site restoration, construction of pipelines, seasonal restrictions on operations, public access to, or use of the leased lands, and avoidance of seismic hazards. The royalty modification will not result in additional restrictions or limitations on access to surface lands or to public and navigable waters. All lease operations are subject to a coastal zone consistency determination, and must comply with the terms of both the State and North Slope Borough coastal zone management plans.

The approval of the royalty modification has no environmental impact itself. The Commissioner's approval of the royalty modification is an administrative action, which by itself does not convey any authority to conduct operations on the leases, within the development area, unit or participating area. Pioneer must still obtain approval of a Unit Plan of Operations and various permits from state agencies before initiating activities. Pioneer plans to develop the area though ice roads, which will leave no trace after they melt. The island facilities will also be constructed during the winter. The planned installation of modular facilities will further minimize impact to the environment by minimizing the required surface area of the island.

D. Summary of Public Comments

During the 30-day public comment period, December 20, 2005, through 5pm January 18, 2006, DNR received twelve comments from the public. Eleven of these voiced support for the granting of royalty modification to Pioneer's Oooguruk development. One comment asked for further clarification of the "royalty ramp-up" terms. In response to that request, DNR has clarified the ramp-up terms in this Final Findings and Determination. The comments are summarized by issue below. The original comments are included as Attachment 11. In accordance with AS 38.05.80 (j)(11)(C) & (E), DNR will transmit a copy of the Final Findings and Determination to the lessees and make copies of it available to each person who submitted comment and filed a request for the copies. As of the signing of this Final Findings and Determination, DNR has not received any requests for copies.

Issue	**Comment and DNR Response**
Royalty Modification terms Paragraph 1.b "Ramp-up" terms.	Request for Clarification. Letter requests that DNR further clarify that the fixed royalty rate for ADLs 389950, 389952, 389954, 389958, 389959 will return to the original rate of 16.6667 percent at the end of ramp-up. **Response to Comment** DNR has clarified the terms in paragraph 1a and 1b.
Royalty Modification terms protect State's Interest	**Response to Comment** Implementation of AS 38.05.180(j) provides the State the authority and guidance to promote economically marginal projects while protecting the State's interest through a modification mechanism which helps the State share in the "upside" of a project.

Increase Crude Production

Response to Comment

Successful development of the Oooguruk resources will result in increased crude production in the State of Alaska.

Strengthen economy:
Provide more job and business opportunities for Alaskans

Response to Comment

The total capital, ($460,000,000.00 which includes well costs, equipment, eligible capitalized expenses, etc. in addition to infrastructure), Pioneer will spend to develop Oooguruk will increase the economic base and therefore provide more opportunities for individuals and businesses.

Support economically marginal project

Response to Comment

Implementation of AS 38.05.180(j) provides the State the authority and guidance to promote economically marginal projects while protecting the State's interest.

Strong message to Independents that Alaska is Open for Business

Response to Comment

Implementation of AS 38.05.180(j) allows for promotion of marginal field production of Alaska's North Slope which is of particular value given that many existing fields are in decline.

VII. FINDINGS AND DETERMINATION

1. Pioneer's application for royalty modification on ADLs 355036, 355037, 355038, 355039, 389950, 389952, 389954, 389958, and 389959 meets the requirements for consideration as set out in AS 38.05.180(j)(1)(A). Pioneer 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 Cretaceous Kuparuk C and Jurassic Nuiqsut pools in the Oooguruk field have been sufficiently delineated to the satisfaction of the Commissioner for the purpose of granting royalty modification; the pools have not previously produced oil or gas for sale; and oil or gas production from the pools would not otherwise be economically feasible.

3. Pioneer has made a clear and convincing showing that a royalty modification meets the requirements of AS 38.05.180(j)(1)(A), and is in the best interests of the State.

4. The Oooguruk Development royalty relief mechanism will be implemented as follows:

a. A five percent royalty rate will be in effect for production from the delineated pools until NPS payments first become due to the State from ADL 355036 as calculated under 11 AAC 83.201 – 11 AAC 83.295. The first month following the month when NPS payments first become due to the State is the month when a four-year royalty modification phase-out commences for all nine leases subject to the royalty modification.

b. At the beginning of each of the four 12-month periods following the month when NPS payments first become due to the State from ADL 355036 the royalty rate for each of the nine leases will be increased by 1.875 percent, resulting in a cumulative increase of 7.5 percent, (four years X 1.875 percent/year). At the beginning of the fourth 12-month period after NPS payments first become due to the State from ADL 355036, the fixed royalty rate for ADLs 355036, 355037, 355038, and 355039 will be restored to 12.5 percent and the NPS rate will remain at 30 percent. At the beginning of the fourth 12-month period after NPS payments first become due to the State from ADL 355036, the royalty rate for ADLs 389950, 389952, 389954, 389958, and 389959 will be immediately restored to a full 16.6667 percent.

c. No additional recapture mechanism beyond the net profit share is included in the royalty modification mechanism.

5. The Oooguruk project as set out in the amended application must be sanctioned, (in-house approval and funding), by Pioneer by December 31, 2007. If Pioneer does not provide project sanction documents and AFEs to DNR by December 31, 2007, this royalty relief is rescinded.

6. If Oooguruk project "facilities capex" (including, but not limited to island construction, surface equipment, and flowline bundle.), costs less than 75 percent of the amount set out in the amended application, $246 million, this royalty relief is rescinded.

7. The NPS lease regulations set out in 11 AAC 83.201 – 11 AAC 83.295 remain in full force and effect. However, Pioneer's request that the current unaudited NPS lease balance of $80,000,000.00 as of January 1, 2005, be deemed true and correct and not be subject to future adjustment resulting from audit, is approved.

8. The $80,000,000.00 NPS lease balance will be allocated to the NPS leases (ADLs 355036, 355037, 355038, and 355039) pursuant to the final participating area redetermination.

9. Pioneer requested that "Oooguruk [be] treated as separate and distinct from KPA (Kuparuk Participating Area) for ELF factor calculation, resulting in a severance tax that is effectively zero." Severance tax issues are within the jurisdiction of the Department of Revenue and not affected by this Findings and Determination.

10. This royalty modification is not assignable without prior written approval of the Commissioner. This modification is based on the financial and technical data supplied to the Commissioner in the amended application and on Pioneer's unique showing that production would not be economical from these Oooguruk pools with the modification approved here. The Commissioner will not approve a transfer of the royalty modification unless the assignee also makes a clear and convincing showing that the modification meets the requirements of AS 38.05.180(j)(1) and is in the best interests of the State.

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Michael L. Menge Date
Commissioner

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

VIII. ATTACHMENTS

1. AS 38.05.180(j)
2. Copy of Public Notice Issuance
3. List of Certified Wells on subject leases
4. Oooguruk Unit Agreement, Exhibit B
5. Figures 2A and 2B Preliminary Participating Area & Unit Expansion Maps
6. Summary of applicant work sessions
7. ANS price forecast, Alaska State Department of Revenue
8. North Slope of Alaska Facility Sharing Study
9. Charter for Development of the Alaskan North Slope
10. 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

    Initial Application for Royalty Modification, Pioneer, May 20, 2005
    Amended Application for Royalty Modification,
    Pioneer, November 1, 2005
    Econ One, Presentation to Legislature, August, 2005
    "Presentation On Alaska Gas Pipeline Project, Investment
    Decision-Making by Oil and Gas Companies"
    DNR Flow chart of decision process metrics
    DNR Model printouts to support confidential analysis
11. Public Comments