PRUDHOE BAY UNIT

APPLICATION FOR THE FORMATION OF THE RAVEN PARTICIPATING AREA

FINDINGS AND DECISION OF THE DIRECTOR OF THE DIVISION OF OIL AND GAS UNDER DELEGATION OF AUTHORITY FROM THE COMISSIONER, DEPARTMENT OF NATURAL RESOURCES, STATE OF ALASKA

December 21, 2007

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Attachments:

I. INTRODUCTION, BACKGROUND, AND CONCLUSION

BP Exploration Alaska, Inc. (BPXA), the operator of the Prudhoe Bay Unit (PBU), on behalf of itself and the other PBU Working Interest Owners (WIO), Chevron U.S.A. (Chevron), Inc., ConocoPhillips Alaska Inc. (CPAI), ExxonMobil Alaska Production Inc. (Exxon), and Forest Oil Corporation (Forest), applied (Application) on February 8, 2006, to the State of Alaska, Department of Natural Resources (DNR), Division of Oil and Gas (Division), to form the Raven Participating Area (RPA) in the PBU.

The leases are currently owned by BPXA and the other PBU WIOs, Chevron, CPAI, and Exxon, with the same tract ownership percentages in each of the leases, which is common to all of the PBU. Forest assigned its ownership interests to BPXA, CPAI, and Exxon, effective September 12, 2006, so that the following ownership interests currently apply:

BPXA-26.360567%; CPAI – 36.076746%; Exxon – 36.402687%; and Chevron – 1.16%.

The proposed RPA encompasses oil-bearing sands within the Permo-Triassic interval, including the Ivishak Sandstone and Sag River Formation (Raven Reservoirs), which underlie the Niakuk Kuparak Reservoir.

BPXA provided geologic, geophysical, and engineering (G&G) data supporting the formation of the RPA. Production from tract operations within the proposed RPA has demonstrated the potential of this hydrocarbon accumulation.

Currently, there are two producing wells and one injector well in the proposed RPA, which is currently producing under a tract operation approval from the Division pending the approval of this Application. BPXA will combine production from the RPA with production from other Greater Point McIntyre field production and process it in the Lisburne Production Center (LPC).

As conditioned in the Findings and Decision, the Division approves the RPA.

II. APPLICATION FOR THE RAVEN PARTICIPATING AREA

Division staff attended pre-Application meetings on September 15 and 26, 2005, and January 25, 2006. BPXA provided overviews of the proposed RPA, drilling results, performance data, simulation model results, and applicable G&G data, including maps, some of which are confidential. BPXA subsequently submitted the Application to form the RPA on February 8, 2006. An additional meeting took place on March 7, 2006, with follow-up discussion and correspondence the next weeks.

The proposed RPA encompasses 1,615 acres. It covers portions of Sections 24, 25, 26 and 36 of T12N, R15E and Sections 29, 30 and 31 of T12N, R16E, Umiat Meridian, from three state leases-- ADLs 34625, 34630, and 34635.

Attachment #1 includes two RPA maps, and Attachment #2 is a description of the tracts and ownership schedule for the RPA.

The Division has delayed approving the Application pending its decision on BPXA's application to combine the Niakuk and West Niakuk Participating Areas into the proposed Combined Niakuk Participating area (CNPA).

III. DISCUSSION OF THE DECISION CRITERIA

The DNR Commissioner (Commissioner) reviews unit-related applications, including the formation of participating areas, under AS 38.05.180(p) and 11 AAC 83.303—11 AAC 83.395. By memorandum dated September 30, 1999, the Commissioner approved a revision of Department Order 003 and delegated this authority to the Division Director. This Finding and Decision evaluates the Application based on the criteria set out in 11 AAC 83.303 (a) and (b). A discussion of the subsection (b) criteria, as they apply to this Application, is set out directly below, followed by a discussion of the subsection (a) criteria.

A) Decision Criteria Considered under 11 AAC 83.303(b)

1) Prior Exploration and Development Activities and the Geological and Engineering Characteristics of the Reservoir

Under 11 AAC 83.351(a) a participating area "may include only the land reasonably known to be underlain by hydrocarbons and known or reasonably estimated through the use of G&G data to be capable of producing hydrocarbons in paying quantities."

The proposed RPA boundary is based on the known extent of the Raven Reservoirs using G&G data. BPXA submitted the following technical data to support the Application: location map, type log, core data, confidential cross sections, top Sag River Formation and top Ivishak Sandstone structure maps, Sag River Formation and Ivishak Sandstone gross oil and gross gas thickness maps, confidential seismic lines and additional well logs. The Division will hold these data confidential under AS 38.05.035(a)(9)(C) and 11 ACC 96.220.

The Raven Reservoirs are located below the Niakuk Oil Pool within the boundaries of the PBU. The RPA covers portions of Sections 24, 25, 26 and 36 of T12N-R15E and Sections 29, 30 and 31 of T12N-R16E, Umiat Meridian. The RPA is defined by the top Sag River Formation structural closure. Seismic coverage over the area of the proposed PA is provided by the LI-NI 3D survey acquired by Western Geophysical for Sohio/BP (permit MLUP-85-132-01) in the first quarter of 1986. Structure maps for the Raven Reservoirs were generated by BP using the 3D volume. An uncertainty resides in the accuracy of any depth map derived from seismic data for an area that is located in the onshore-offshore transition zone, as in the case of the RPA. Because of the rapid lateral changes in the shallow permafrost section that occur in the transition zone, depth maps created from seismic data can sometimes contain significant errors where well penetrations are relatively sparse.

The Raven Reservoirs consist of the Sag River Formation and the Ivishak Sandstone Member of the Sadlerochit Group. The intervening Shublik Formation may eventually contribute to production of hydrocarbons in the RPA, but that formation is generally considered to be a low permeability carbonate. Potential for incidental production from the Shublik could occur as a result of the existence of natural fractures; however, there is no currently planned development for the Shublik Formation. The Sag River Formation and Ivishak Sandstone are Permo-Triassic in age. The Raven oil pool is that interval that correlates with and is found from 10,628 feet md to 11,165 feet md within the BP Niakuk 5 well. The proposed RPA encompasses 1,615 acres. Data provided in the Application indicates that both the Sag River Formation and the Ivishak Sandstone are proven capable of producing hydrocarbons in paying quantities.

The Permo-Triassic stratigraphy reflects an overall transgressive succession from fluvio-deltaic Ivishak sandstones, conglomerates, siltstones and shales, to shelfal, marine transgressive deposits of the Sag River Formation. The Ivishak Sandstone of the Sadlerochit Group was deposited in a multistoried fluvio-deltaic system. The Ivishak Sandstone is the primary reservoir at the Prudhoe Bay oil field. It is overlain by the Shublik Formation. The Shublik Formation represents deposits of a transgressive, shallow marine carbonate platform. The Shublik Formation is overlain by the Sag River

Formation. The Sag River Formation represents stacked, aggradational to transgressive shelfal deposits of several very fine to fine grained, glauconitic, quartz-rich sandstones.

Numerous small accumulations of oil and gas have been either tested or produced from the Ivishak Sandstone north of the Prudhoe Bay bounding fault, notably at Northstar, North Prudhoe Bay, Eider, and in the Gwydyr Bay area. Similarly, oil and gas have been produced from the Sag River Formation north of Prudhoe Bay at Milne Point Unit, and North Prudhoe Bay. These accumulations, like the Raven Reservoirs, are structural closures. Faulting within the RPA, combined with the internal stratigraphy of the Sag River Formation and the Ivishak Sandstone, has influenced gas-oil contacts. The water-oil contact appears to be common across the participating area. Because of internal faulting four areas are defined within the RPA--the North and South Fault blocks and the East and South areas. The North and South Fault blocks contain the bulk of the proven reserves.

Previous wells, both exploratory and early development, in the immediate area that have penetrated the Sag River Formation and the Ivishak Sandstone include the Niakuk 1A, 4, 5, NK-19, NK-19A, NK-38A, NK-38APB1 and NK-43 wells.

Niakuk 1A was drilled in March, 1976. It contains partial cores of both the Sag River Formation and the Ivishak Sandstone. The Sag River Formation is approximately 75' thick and the Ivishak Sandstone is 313' thick at this location. Minor hydrocarbon shows were found in the Sag River Formation, but the Ivishak is down dip and wet at this location. Log data indicates fair-to-poor porosity in the Sag River and good porosity in the Ivishak Sandstone.

The Niakuk 4 well was drilled in January, 1985. The Sag River Formation is faulted out in this well, but the Ivishak Sandstone was logged and cored. The well was not tested. The Ivishak Sandstone is hydrocarbon bearing with Lowest-Known-Oil down to approximately -9,874 feet true vertical depth subsea (TVDss). Ivishak Sandstone core data indicates average porosity of 20.5% and permeability that ranges from 385 millidarcies (md) to 140md. It is 318' TVD thick at this location. Repeat Formation Test (RFT) data indicates a gas gradient in the upper Ivishak of 0.11psi/ft. A gas-oil contact of -9,780 feet TVDss is interpreted based on data from the RFT and oil saturation from core at Niakuk 4. No oil-water-contact was seen in Niakuk 4. Additional wells drilled in the North Fault Block (NK-38A and NK-65A) confirm a gas–oil contact of -9,780 feet TVDss for the North Fault Block in the Ivishak Sandstone.

Thick overbank shale in the lower Ivishak Sandstone at Niakuk 4, which is correlative across the Raven reservoir, creates compartmentalization of the Ivishak Sandstone when combined with the structural trap. Minor faulting north of the Prudhoe Bounding fault further compartmentalizes the Ivishak Sandstone at Raven as evidenced by pressure data collected in the North and South Fault Blocks at wells NK-38A and NK-38APB1 respectively. This compartmentalization may be one reason a deeper gas-oil contact exists in the South Fault Block at -9850 feet TVDss.

The Niakuk 5 well was drilled in March, 1985. This well initially tested 32 API gravity oil from the Sag River Formation. Niakuk 5 was partially cored in the Sag River. Core porosity averages 20.6% and core permeability averages 13.3md with a range of 2.2md to 27md. Sag River Formation DST data indicates the Sag River gas-oil contact is above -9800 feet TVDss and the oil-water contact is at or below -9850 feet TVDss.

An extended Sag River Formation production test from well NK-43 in 2001 produced a high GOR condensate (49 deg. API) along with minor black oil. The well tested at a rate of 600 STB of hydrocarbons with a gas oil ratio (GOR) of 14,000scf/stb. This data suggests that the NK-43 well located in the East Area of the RPA contains gas, condensate and oil in the Sag River Formation. Down dip in the South Fault Block the Niakuk 5 well test from 1985 indicates the Sag River Formation is oil bearing. The Sag River Formation is wet further down dip as seen during testing in the NK-19A well.

The NK-38APB1 well in the South Fault Block contains the most complete set of engineering data regarding fluid and pressure characteristics. MDT (wireline formation fluid and pressure sampling log), pressure data and log curves indicate four fluids in the well and three slightly different pressure gradients (Sag River Formation, Upper Ivishak Sandstone and Lower Ivishak Sandstone). This will make effective reservoir management complex and EOR fluid injectivity will need to be carefully managed.

Core data and petrophysical evaluation of well logs were used to estimate rock properties of the RPA reservoirs. The following table summarizes the rock properties used to determine in-place hydrocarbon volumes.

Reservoir	Porosity	Net/Gross	Sw
Ivishak Sandstone	20%	88%	40%
Sag River Formation	20%	55%	40%

Due to various pressures in the different areas of the RPA, the initial oil Formation Volume Factor (Boi) for the Ivishak ranges from 1.960 to 1.833rb/stb; initial Solution Gas-Oil Ratio (Rsi) ranges from 1412scf/stb to 1600 scf/stb and initial gas Formation Volume Factor (Bgi) ranges from 0.62 rb/Mscf to 0.66 rb/Mscf. Average fluid properties for the Sag River Formation are Boi, 1.960rb/stb; Rsi, 1600scf/stb and Bgi, 0.62 rb/Mscf.

Original oil, condensate and gas volumes in place are summarized in the table below.

Raven In-Place Oil Volume Summary (MMBO)

	OIL	CONDENSATE	TOTAL
Ivishak Sandstone	6.9 to 11.4	2.3 to 3.8	9.2 to 15.2
Sag River Formation	3.5 to 5.8	1.3 to 2.2	4.8 to 8.0
Total	10.4 to 17.2	3.6 to 6.0	14.0 to 23.2

Raven In Place Gas Volume Summary (bcf)

	FREE GAS	SOLUTION GAS	TOTAL
Ivishak Sandstone	35.4 to 59.0	10.4 to 17.3	45.8 to 76.3
Sag River Formation	20.4 to 33.9	5.3 to 8.8	25.7 to 42.7
Total	55.8 to 92.9	15.7 to 26.1	71.5 to 119.0

Based on the foregoing data, the Application proposes a participating area that encompasses the reasonably known limits of the Raven Reservoirs that is capable of producing hydrocarbons in paying quantities.

2) The Applicant's Plan of Development for the RPA

BPXA has submitted plans of development for the RPA as a part of the Greater Point McIntyre area annual Plan of Development (POD) Review process. On October 1, 2007, the Division approved the POD for the proposed RPA. That approval remains in effect.

3) The Environmental Costs and Benefits

Approval of the RPA is only one step in the process of obtaining permission to drill a well or wells or develop the known reservoirs within the unit area. The approval of the RPA itself has no environmental impact. The approval does not entail any environmental costs in addition to those that may occur when permits are issued to conduct lease-by-lease exploration or development. Approval of the RPA is an administrative action that does not convey any authority to conduct any operations on the surface within the unit area. Unitization does not waive or reduce the effectiveness of the mitigation measures that condition the lessee's right to conduct operations on these leases. The unit operator also must obtain permits from various agencies before drilling a well or wells or initiating development activities to produce known reservoirs within the RPA. The operator must obtain the Division's approval of a plan of operations before the unit operator performs any field operations 11 AAC 83.346. The Plan of Operations permit undergoes a multi-agency review that includes a public notice and 30-day comment period. A plan of operations must describe the operating procedures designed to prevent or minimize adverse effects on natural resources. When reviewing a plan of operations, the Division will consider the operator's ability to compensate the surface land owner for potential damage sustained to the surface estate and any needed plans for rehabilitation of the unit area. A PBU Plan of Operations is currently in place for the RPA and is independent of subsurface boundaries. PBU leases also contain stipulations designed to protect the environment and address concerns regarding impacts to the area's fish and wildlife species, habitat and subsistence activities, and cultural resources.

The RPA and anticipated activity under the plans of development will affect habitat and subsistence activity less than if the lessees developed the leases individually. RPA plans of development provide for access to existing LPC facilities for consolidated development of the Raven Reservoirs. These efforts as well as other ongoing mitigation measures can reduce the impacts so that the anticipated development related activity is not likely to significantly impact bird, fish, and mammal populations.

Based on the foregoing, the environmental costs and benefits of forming the RPA justify approval of the Application under the section .303(b)(1) criteria.

4) The Economic Costs and Benefits to the State and Other Relevant Factors

4.1 Facility Sharing, Production Allocation, and Metering

The RPA will be developed from the Heald Point drill pad, which is also used to produce oil and gas shared with production from the Niakuk reservoirs. The RPA will share existing PBU facilities and infrastructure, mainly through production processing at the LPC facilities. Raven production will be constrained by the gas and water handling capacity at the LPC. The RPA will receive water injection from the LPC and gas lift gas supplied from the Lisburne high-pressure gas injection system at the Lisburne L5 drillsite. Infrastructure support facilities, including a camp, water, shop, roads, bridges, and airstrip are shared with the Lisburne Participating Area (LPA) and the Initial Participating Area (IPA).

The Application includes, as Attachment #5, the draft Raven Special Supplemental Provisions (SSP) to the Prudhoe Bay Unit Operating Agreement. The SSP provides terms, between the various WIOs, for management and operation of the RPA, such as operator rights, voting provisions, budgeting, disposition of equipment, and claims. BPXA has represented that a final version will be signed upon Division approval of the RPA. BPXA shall submit a final RPA SSP to the Division within 90 days of this Findings and Decision, which must be consistent with the draft version submitted with the Application or highlight any changes from the draft version, and must include all attachments.

BPXA has represented that the third and fourth amendments to the Lisburne SSP (Article 53) provide for RPA use of the LPC and sharing of other Lisburne equipment. On September 29, 2005, BPXA provided a copy of the Lisburne SSP, as amended, as a part of its CNPA application and has asserted that no additional facility sharing documents exist or need to be provided to the Division with the Application. This approval is therefore based on the third and fourth amendments to the Lisburne SSP providing for RPA use of the LPC and sharing of other Lisburne equipment and IPA infrastructure. If as a result of these Findings and Decision, or any other reasons, the PBU WIOs adopt changes to the third and fourth amendments to the Lisburne SSP, or any other provision of the Raven or Lisburne SSPs relevant to RPA facility sharing, BPXA shall provide the changes to the Division within 30 days of their adoption.

RPA production will be allocated and metered in two ways. First, production commingled at the surface with other PBU oil pools will be allocated and metered under the terms and conditions set out in Alaska Oil and Gas Conservation Commission (AOGCC) Conservation Order No. 570.004, dated October 9, 2007, including as follows:

- conduct well tests to determine production rates for each well;
- calculate each well's theoretical monthly production ("TMP") based on well test rates and actual time on production;
- sum the TMP volume for all wells in all pools;

- determine an allocation factor as the ratio of the metered volume to the TMP for all wells in all pools (i.e., metered/TMP); and

- calculate each well's actual monthly production ("AMP") volume as: AMP = TMP x Allocation Factor.

Natural gas liquids (NGL) will be allocated based on actual gas production volumes and NGL process simulations. Process simulations will be updated at least once per year based on NGL samples.

Each producing well will be tested at least twice each month. Wells that have been shut in and cannot meet the twice monthly test frequency must be tested within five days of startup. All available test separator capacity within the constraints imposed by operating conditions must be used for well testing.

Use of new multi-phase meters remains in the research phase and are not approved for full-scale field implementation.

Second, BPXA is currently commingling production from the Kuparak and Raven Reservoirs (separate PAs and reservoirs) down-hole in NK-43 well. The down-hole commingling should result in greater oil recoveries from both reservoirs and is approved for the NK-43.

The commingled production must be allocated to the correct PA and reservoir because the state's royalty oil is valued differently in the RPA and CNPA. It will be allocated between the Raven and Kuparak reservoirs under the terms and conditions set out in AOGCC Administrative Approval CO329B.003, dated October 9, 2007, including as follows:

1. At least twice per year and not less frequently than once every seven months:
    a. samples must be collected from NK-43; and
    b. NK-43 well production must be allocated down-hole between the RPA and CNPA based on a geochemical analysis.

The Division reserves the right to review down-hole sampling, down-hole allocation, well test, and surface allocation data to ensure compliance with the methodologies prescribed in this Decision. The review may include requesting any information the Division deems pertinent to the review, which may include, but is not limited to, inspection of facilities, equipment, and well test data.

4.2 Gas Disposition

The Initial POD states that "Raven produced gas (other than gas extracted as NGLs and blended with crude oil for shipment through TAPS) will be used or consumed for unit operations, or injected into another formation underlying the unit area, prior to initiation of gas sales." The Division recognizes that the WIOs may produce more gas than required for unit operations and therefore approves 1) injecting this excess gas into another formation underlying the unit area and 2) extracting and blending RPA NGLs with crude oil for shipment through TAPS. However, any residue gas from the

RPA injected into another formation underlying the unit area must only be injected into a reservoir that is part of an approved PA in the PBU. Any residue gas from the RPA injected into another formation underlying the unit area will be treated as indigenous natural gas for royalty reporting purposes and the WIOs shall be responsible for royalty payments when the gas is ultimately sold. Any residue gas injected from the RPA into another formation underlying the unit area must be reported and accounted for separately on the LPC Gas Reserves and Debit Report submitted monthly to the Division. The Division will allow RPA gas injection into another formation because it would be overly burdensome for the Division and the RPA WIOs to track and report the relatively small amount of gas produced from the Raven Reservoirs. BPXA has also represented that gas extracted as NGLs and blended with crude oil for shipment through TAPS will be processed the same as Niakuk NGLs, through the Lisburne NGL plant. Therefore, the Division approves extracting NGLs from RPA produced gas at the Lisburne NGL plant. All NGLs manufactured from RPA produced gas at the Lisburne NGL plant must be accounted for and reported as Raven NGLs.

4.3 Tract Allocation Schedule

Attachment #2 is the proposed RPA Tract Description and Ownership Schedule included with the Application. BPXA has represented that RPA tract allocations (participation percentages) are based on original oil in place for both the Sag River and Ivishak reservoirs and recoverable hydrocarbon liquids from the Sag River reservoir, all at surface conditions. BPXA has represented that hydrocarbon liquids from the Sag River are included in the tract participation percentages because NK-43 Sag River test production had a relatively high condensate yield (65bbl/Mscf) during prior testing and is a 40 API gravity condensate produced from the gas cap, with a minor black oil component produced from the oil leg.

When the Application was submitted, the WIOs owned the following percentages of RPA production: BPXA--26.355356; Chevron--1.16; Exxon-- 36.395491; CPAI--36.069385; and Forest--0.019768. Effective September 1, 2006, Forest's ownership was assigned to BPXA, CPAI, and Exxon. The revised Tract Description and Ownership Schedule percentages are: BPXA--26.360567; CPAI--36.076746; Exxon--36.402687; and Chevron--1.16. Within 30 days of this Decision, BPXA shall submit on behalf of the WIOs, a revised RPA Tract Description and Ownership Schedule that reflects this revision.

4.4 Field Costs

Because the RPA approved by this Findings and Decision is within the original PBU, the 1980 Royalty Settlement Agreement governs the field cost allowance for the state's royalty share of production from the RPA.

In summary, the economic benefits of forming the RPA and developing the Raven Reservoirs outweigh the costs of not approving the RPA. The WIOs have made meaningful commitments to develop the RPA. Conditional approval of the proposed RPA will result in both short and long-term economic benefits to the state. Development and production from the RPA will provide royalty and tax revenues to the state over the life of the field and the lessees may reinvest revenues in new exploration and development in the state. Royalty, tax, and employment benefits derived from production and economic development will far exceed any additional administrative burdens associated with permitting RPA activities, administering the unit leases, or collecting royalties on production. Therefore, the Division's evaluation of the section .303(b)(4) economic criteria supports approval of the Application.

B) Decision Criteria Considered under 11 AAC 83.303(a)

1) Promote the Conservation of all Natural Resources and Prevent Economic and Physical Waste

Through unitization and the formation of participating areas, the assignment of undivided equity interests in the oil and gas reservoirs to each lease and competition between lessees for their share of production is resolved so that resources can be conserved and economic and physical waste prevented. The RPA owners have agreed to share existing facilities and infrastructure and have proposed plans of development that are intended to allow the RPA to be produced most economically and efficiently, and in a way that prevents economic and physical waste and promotes the conservation of both surface and subsurface resources through unitized (rather than lease-by-lease) development.

The RPA will conserve resources by sharing production facilities and support infrastructure with the Niakuk, Lisburne, Pt. McIntyre, and Initial Participating Areas to avoid duplication of facilities and to minimize utilization of materials, gravel, power, staff, and other resources. A smaller facility footprint will result from the shared facilities and infrastructure, which will also minimize the economic and physical waste of surface resources. Further, the RPA provides a regulatory framework for application of mitigation measures so that resources can be conserved and economic and physical waste prevented. Compliance with these the Unit Plan of Operations will conserve, and prevent economic and physical waste of, surface resources.

The RPA will provide for efficient, integrated development of the Raven Reservoirs. The RPA will promote efficient development of reservoirs, efficient well spacing, and rational operating and reservoir management strategies. The RPA will also allow for the development of economically marginal hydrocarbon accumulations due to the lower capital and operating costs resulting from commingled production and common facilities. Marginally economic reserves, which otherwise would not be produced on a lease-by-lease basis, can be produced from the RPA in combination with more productive leases. The RPA will allow more optimal pressure maintenance and secondary recovery through a joint, unitized effort of WIOs. Maximizing oil and gas recovery results in a more optimal use of the resource and prevents economic and physical waste.

Formation of the RPA is expected to reduce costs and environmental impacts associated with development of the Raven Reservoirs, thereby conserving resources, preventing economic and physical waste, expediting development of reserves, and promoting more optimal ultimate recovery of oil and gas from the RPA. Therefore, the Division's evaluation of the section .303(a)(1) and (2) criteria supports approval of the Application

2) Provide for the Protection of all Parties of Interest, Including the State

The RPA protects the economic interests of the state and a unified plan will be more likely to maximize hydrocarbon recovery and revenue to the state. Formation of the RPA advances the efficient evaluation and development of the hydrocarbon resources while minimizing impacts to the area's cultural, biological, and environmental resources.

Formation of the RPA also protects the economic interests of the WIOs. The approved production allocation schedule agreed to by the WIOs ensures an equitable allocation of cost and revenue.

On April 21, 2006, the Division received a letter from Mr. Ray Givens, attorney for the Oenga heirs, who own surface rights to Heald Point. The letter requests that the Division defer its RPA approval until the surface lease between the Oenga heirs and BPXA is modified to allow for production from the Raven Reservoirs through the Heald Point production facilities. The heirs assert that the current lease language does not authorize that activity. The Oenga heirs indicated in a similar request to the AOGCC that they object to the establishment of pool rules for the Raven Reservoir and that although they do not object to exploration or development of North Slope oil reserves, they are concerned that "surface leases for oil production facilities authorize the use made of those facilities before production begins." They assert that the Oenga heirs' lease with BPXA authorizes production from Niakuk, but not from any other pool, including from the Raven Reservoirs. The letter is included as Attachment # 5 to this Findings and Decision.

On May 26, 2006 the Division received a letter from Guess & Rudd, attorney for BPXA, providing its response to Mr. Given's letter and asking that the Division act on the Application without delay.

On June 21, 2006, the Division received a second letter from Mr. Ray Givens responding to the Guess & Rudd letter who again asked the Division to defer its RPA approval until the surface lease between the Oenga heirs and BPXA is modified.

The Division will not further delay this Decision because of these requests. This Decision deals with subsurface issues surrounding the establishment of the participating area. The issue raised in the letters focuses on resolution of a private dispute regarding individual surface rights--an issue separate and apart from this Decision. It is a dispute that must be resolved between BPXA and the Oenga heirs.

IV. Findings and Decision

1. The RPA is approved effective on the first day of the month following this approval--January 1, 2008. This approval is subject to applicable state statutes and regulations and to the conditions set out in this Findings and Decision. The formation of the RPA is necessary and advisable to protect the public interest. 11 AAC 83.303.

2. The available G&G data indicates that the RPA is underlain by hydrocarbons and known and reasonably estimated through the use of the data to be capable of production or contributing to production in sufficient quantities to justify the formation of the RPA. The lands described in Attachment #2 to this Decision are included in the RPA.

3. BPXA shall conduct diligent exploration, delineation, and production of the Raven Reservoirs underlying the approved RPA under the plans of development and operations approved by the Division. BPXA may not commence drilling, development, or production operations until it acquires all required permits.

4. The accounting unit code for the RPA is "PBRA." The WIOs shall reference this account code on the monthly operator and royalty reports submitted to the Division for RPA production. The accounting code becomes effective on the first day of the month following this approval—January 1, 2008. In the case where production from CNPA Kuparak Reservoir is commingled downhole with production from the proposed Raven Reservoirs, such as is the case with NK-43, only the portion of production allocated to the RPA Raven Reservoirs must be referenced to the new accounting unit code of PBRA on the monthly operator and royalty reports submitted to the Division for RPA production. The CNPA Kuparak Reservoir portion must be appropriately allocated to its approved accounting code on the CNPA monthly operator and royalty reports submitted to the Division.

5. The formation of the RPA divides costs and allocates produced hydrocarbons in a manner currently acceptable to all affected WIOs. Under 11 AAC 83.351(a) and 11 AAC 83.371(a), and in accordance with the terms set out in this Findings and Decision, the Division approves the allocations of production and costs for the tracts within the RPA set out in Attachment #2, but subject to a revision of the ownership schedule as described in Section III .A. 4.3 of this Decision. Within 30 days of this Decision, BPXA shall submit on behalf of the WIOs, a revised RPA Tract Description and Ownership Schedule that reflects the transfer of Forest's interest.

6. BPXA may commingle RPA production with other PBU production in PBU surface facilities before custody transfer. Terms for use of those facilities are amendments to the PBU Operating Agreement and referred to in Attachment #5 to the Application, the draft Raven Special Supplemental Provisions (SSP) to the Prudhoe Bay Unit Operating Agreement, and in the Lisburne SSP, as amended and provided to the Division on September 29, 2005, as a part of BPXA's CNPA application. Section III.A.4 of this Findings and Decision describes BPXA's submittals and representations regarding these documents. BPXA shall submit any

additional SSP and facility sharing documents in accordance with the terms and conditions set out in Section III.A.4.1 of this Findings and Decision.

7. RPA production must be allocated and metered according to terms set out in this Findings and Decision.

8. The Division recognizes that the WIOs may produce more gas than needed for unit operations and approves 1) injecting this excess gas into another formation underlying the unit area and 2) extracting NGLs and blending them with crude oil for shipment through TAPS, subject to terms and conditions set out in Section III.A.4.2 of this Findings and Decision.

9. RPA data submittal requirements are listed in Attachment #5. BPXA shall provide this data to the Division, to the extent not already provided, in support of any RPA modification or future RPA plans of development as requested by the Division.

A person affected by this decision may appeal it, in accordance with 11 AAC 02. Any appeal must be received within 20 calendar days after the date of "issuance" of this decision, as defined in 11 AAC 02.040 (c) and (d), and may be mailed or delivered to Tom Irwin, Commissioner, Department of Natural Resources, 550 W. 7th Avenue, Suite 1400, Anchorage, Alaska 99501; faxed to 1-907-269-8918; or sent by electronic mail to: dnr.appeals@alaska.gov. If no appeal is filed by the appeal deadline, this decision becomes a final administrative order and decision of the Department on the 31st day after issuance. An eligible person must first appeal this decision in accordance with 11 AAC 02 before appealing this decision to Superior Court. A copy of 11 AAC 02 may be obtained from any regional information office of the Department of Natural Resources.

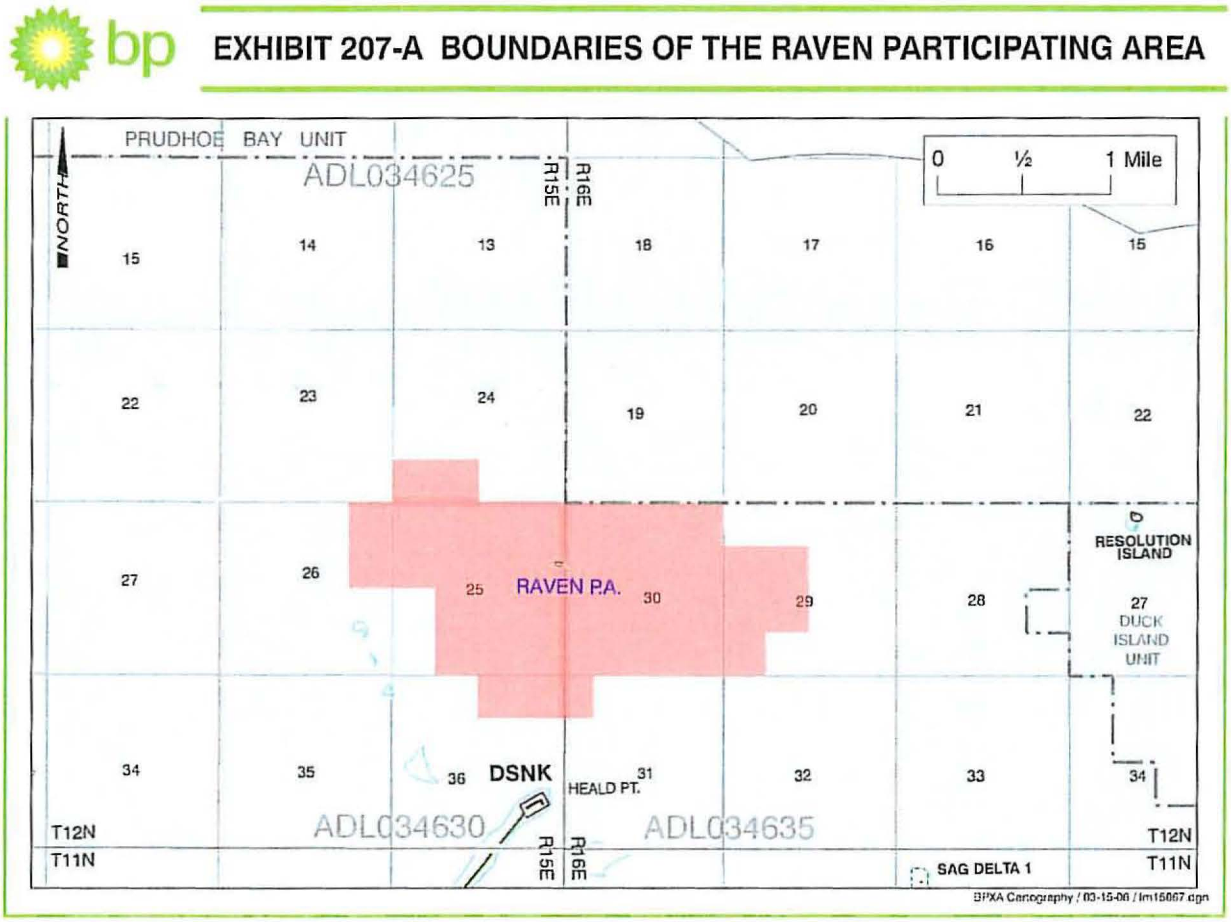
Kevin Banks, Acting Director
Division of Oil and Gas

12-20-07
Date

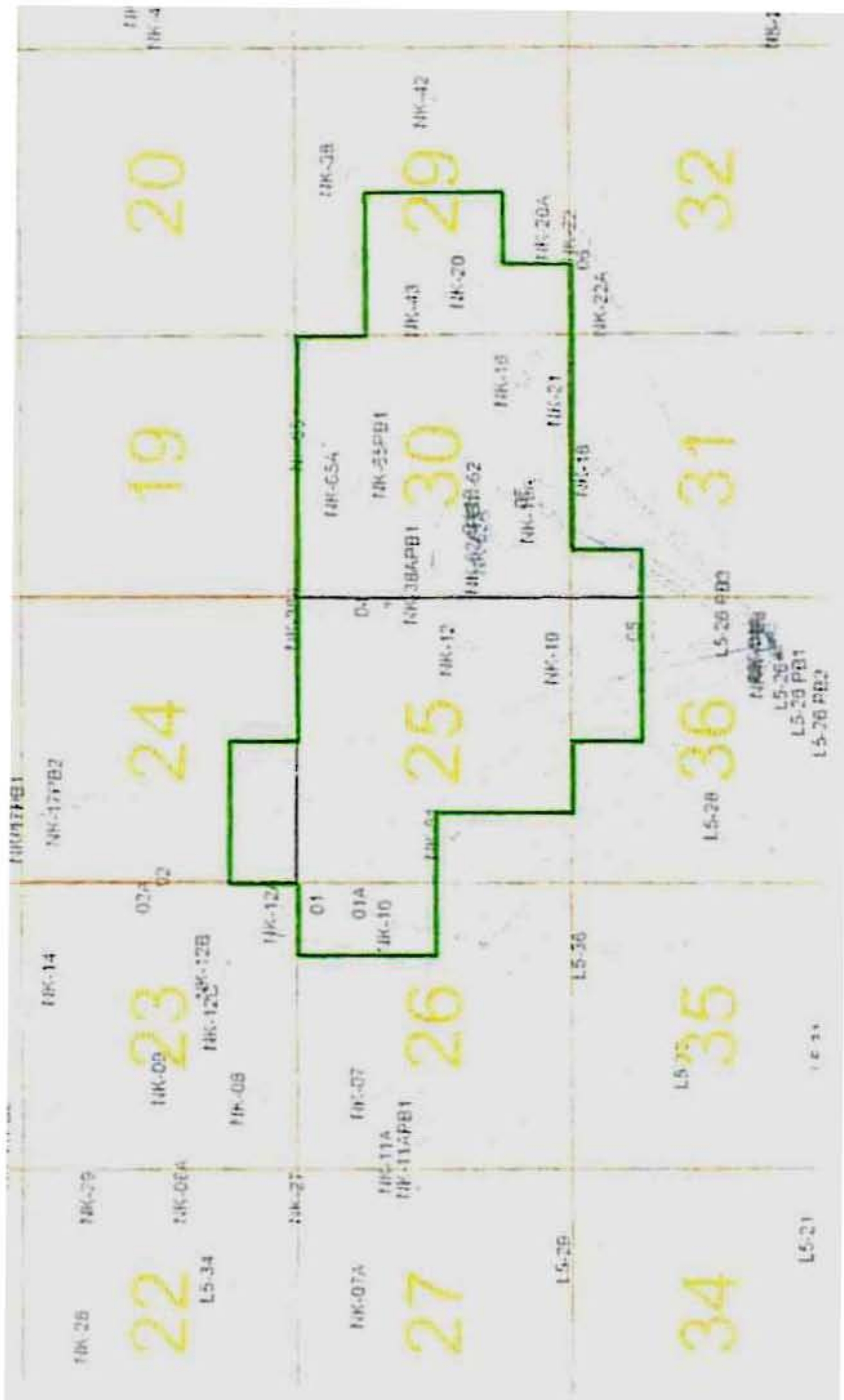
Attachments:

Attachment #1 - Maps of the RPA
Attachment #2 – Proposed RPA Tract Description and Ownership Schedule
Attachment #3 – Abbreviations
Attachment #4 – Objection to formation of the RPA
Attachment #5 - RPA Data Submittal Requirement

Attachment #1 - Maps of the RPA



Raven Participating Area Boundary
December 21, 2007



Attachment #2 – Proposed RPA Tract Description and Ownership Schedule

Tract	ADL	T & R, U.M.	Section: Description		Acres	Roy-alty, %	--------Tract Ownership %------------					Tract Particip-ation %
							BPXA	CPAI	Exxon Mobil	Chevron	Forest	
4	034625	12N-15E	Sec 24	S/2SW/4	80	12.5	26.355356	36.069385	36.395491	1.1600000	0.019768	0.904
31	034630	12N-15E	Sec 25 Sec 26 Sec 36	E/2, NW4, E/2SW/4 E/2NE/4 N/2NE/4	720	12.5	26.355356	36.069385	36.395491	1.1600000	0.019768	50.429
32	034635	12N-16E	Sec 29 Sec 30 Sec 31	S/2NW/4, N/2SW/4, SW/4SW/4 All NW/4NW/4	815	12.5	26.355356	36.069385	36.395491	1.1600000	0.019768	48.667

Total = 1,615 acres

Attachment #3 – Abbreviations

BPXA - BP Exploration (Alaska) Inc.
CPAI - ConocoPhillips Alaska, Inc.
Forest - Forest Oil Corporation
ExxonMobil - ExxonMobil Alaska Production Inc.
Chevron - Chevron U.S.A. Inc

Attachment #4 – Objection to the Formation of the RPA

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April 18, 2006

Bill Van Dyke, Acting Director
Director/Administration
Alaska Department of Natural Resources
550 West 7th Avenue, Suite 800
Anchorage, Alaska 99501-3560

Re: Prudhoe Bay Unit - Objection to Application for Raven P.A.

Dear Mr. Van Dyke:

I write to you as the attorney of the Heirs of Andrew Oenga (Oenga Heirs) regarding BIA Allotment # F-14632 and BIA Lease # F-89-01. The purpose of this letter is to memorialize the Oenga Heirs' objection to the <u>current</u> establishment of a Raven Participation Area (P.A).

The Oenga Heirs are the owners of BIA Allotment # F-14632, Parcel B - Heald Point, on the northeast edge of Prudhoe Bay. That allotment is subject to Lease # F-89-01. The lessor interests are now held by the Oenga Heirs, as owner, and the United States, as their trustee. The lessee interests are currently held by BP Exploration (Alaska) Inc. (BPX) as successor to the original lessee.

The allotment was originally leased for use as a pipeline corridor. BPX has since constructed an oil production facility on the Heald Pont property. The Oenga Heirs understand that 1) BPX is asking the Alaska Oil & Gas Conservation Commission (Commission) to adopt Pool Rules for the Raven oil pool, 2) that BPX is asking the Alaska Department of Natural Resources (Department) to designate a Raven P.A. for the development of the Raven oil pool, and 3) BPX is proposing to use this Heald Point facility as the production facility thru which oil from the Raven P.A. will be produced.

In response, the Oenga Heirs have objected to the Commission's establishment of Pool Rules for the Raven Oil Pool. See Objection (Request for Postponement) To Establishment of Pool Rules - Raven Oil Pool, and letter of April 12, 2006 replying to BPX's response. The attached filings with the Commission are incorporated herein. The Oenga Heirs herein object to the current establishment of a Raven P.A.

Lease # F-89-01 <u>does not authorize</u> BPX to produce oil or gas from the Raven Pool thru the Heald Point property. A copy of the original lease and the first letter amendment/notice regarding the lease are attached and incorporated herein. They have previously been provided to the Commission. While the lease grants broad uses of the Heald Point property, it only allows those uses to be made regarding the "Niakuk Project". Original lease p. 1 (last sentence), p. 2 (first sentence of third paragraph, and "Niakuk Development Project" letter amendment title. This "Niakuk Project" or "Niakuk Development Project" was more specifically referred to by BPX as:

> This Lease provides authorization for BP to construct production facilities to support development of and production from <u>our Niakuk oil accumulation</u>.

July 29, 1993 Lease letter amendment/notice (emphasis added).

This explanation of the limited scope of the lease, in BPX's own words, makes clear that this lease is not applicable to any other oil accumulation, such as the Raven Pool.

For the reasons stated herein, and for those contained in the filings with the Commission, the Oenga Heirs object to the <u>current</u> establishment of a Raven Participation Area (P.A.). The Oenga Heirs are not opposed to the <u>eventual</u> development of the Raven Oil Pool or to the eventual establishment of a Raven P.A. However, this would only be appropriate once the lease for the surface rights of Heald Point, upon which the production facility is located, is amended to authorize such use of the property.

According to the Oenga Heirs' estimates, over $1.5 billion worth of oil from the Niakuk P.A. and the West Niakuk P.A. has been produced thru the Heald Point production pad since its construction twelve years ago. During this period, the Oenga Heirs have been paid on average less than $90,000/year for the use of surface rights on which the production facility is constructed. This gross inequity should not be compounded by allowing yet another unauthorized P.A. to be produced thru the Heald Point facility contrary to the existing lease.

The Oenga Heirs respectfully request that the establishment of any Raven P.A. be deferred until BPX can produce concurrence from all parties with an ownership interest in the Heald Point property that there is the requisite legal authority to produce oil and gas from the Raven Oil Pool thru the Heald Point production facility.

The Department certainly has a valid interest in assuring itself that State oil/gas leases have a legally valid means of production from State leases. The relief requested would be in furtherance of that legitimate Department function in this contentious matter. It would also encourage all parties to reach a fair and reasonable agreement with respect to the production from the Raven Pool thru the Heald Point facility.

Thank you for your consideration.

Sincerely,

Raymond C. Givens
Idaho State Bar # 1695
Washington State Bar # 36029
raygivens@givenslaw.com

On Behalf of Oenga Heirs

RCG:jr
Enclosure

cc: Oenga Heirs
Roger Hudson, Deputy Solicitor, DOI
Dorothy Edwardsen, ICAS
Joseph J. Perkins, Guess & Rudd
John Cyr, BPX

Attachment #5 -
RPA Data Submittal Requirement

General Data Submittal requirement in support of any RPA modification or future RPA Plans of Development as requested by the Division. Data shall include the following:

(a) The lessee shall submit to the Alaska Department of Natural Resources all geological, geophysical and engineering data obtained from the lease within 30 days after completion, abandonment, or suspension of the well and within 30 days after completion or plugging of a well branch, if occurring at a different time. The lessee shall submit to the Alaska Department of Natural Resources data acquired subsequent to well completion within 30 days following acquisition of that data. The state may waive receipt of operational data from some development, service or injection wells. The state will inform the operator of the waiver prior to well completion.

The lessee shall submit the data to the Division of Oil and Gas, Department of Natural Resources.

The data shall include the following:

1. a copy of the well completion report (AOGCC form 10-407) with all attachments, including summaries of perforations open to production, production tests, core data, formation tops or geologic markers, and formation tests.
2. daily drilling reports or a summary report of daily drilling.
3. latitudinal and longitudinal coordinates (based on NAD-27 spheroid) for the completed surface and bottom hole locations, include locations for all plug-backs and pilot holes.
4. Paper and digital copies of all directional surveys, include surveys for all plug-backs and pilot holes.
5. a summary list of all logs run and the depth interval covered by each, also list logs for all plug-backs and pilot holes.
6. a list of formations and other geologic markers encountered and the measured depths (MD) and true vertical depths (TVD) of each.
7. a summary of cored intervals (both conventional and sidewall), including depth, formation name, lithology, presence of oil, gas and water, porosity, fractures and apparent dips, indicate "**none**" in space provided on completion report or in an attachment if no cores were taken.
8. paper and digital copies of all core reports including lab analyses of lithology, porosity, permeability (vertical and horizontal, air and liquid), density, capillary pressure, and fluid saturation, if available.
9. paper and digital copies of all conventional and sidewall core photos (plain light and ultraviolet), if available.
10. identify depth and formation name for oil and gas shows, indicate "**none**" on the completion report or in an attachment if no shows were observed.
11. identify zones of abnormal pressure, indicate "**none**" on the completion report or in an attachment if none were observed.
12. a synopsis or summary of testing and all fluid recovery efforts, including production tests (IP), drill stem tests (DST), wireline formation tests (i.e. repeat formation tests (RFT) and

modular dynamics tests (MDT)), and other production and formation testing data; the summary should include test date, time, depth, formation name, method of operation, recovered fluid type(s) and amount(s), and fluid rate, gas-oil ratio (GOR), oil gravity, pressure, and choke size, when available. If no tests were undertaken, indicate "**none**" where appropriate on the completion report or in an attachment, if tests were undertaken but failed to recover fluids indicate "**no recovery**".

13. paper and digital copies of all pressure build-up, and fluid PVT analyses, if available.
14. copies of all open flow potential test reports and report attachments AOGCC Forms 10-421 .
15. paper and digital copies of well test procedures, field chronologies, and field data; including details – such as interval(s) open to test; volumes of oil, water and gas, BS&S=W, API gravity, gas density; wellhead and downhole pressure; and formation and wellhead temperature, – necessary to fully evaluate the test data.
16. paper and digital copies of geochemical and formation fluid analyses and reports, if available.
17. down hole and surface fluid sampling procedures, field chronologies, raw data, and laboratory test results for all water and hydrocarbon-bearing zones sampled; including details necessary to fully evaluate quality of sample data
18. a copy of the permit to drill (AOGCC form 10-401) and the survey as-built of the well location.
19. paper copy (no sepia copies, please) of all final 2-inch open hole and cased hole logs, including measured depth (MD) and true-vertical depth (TVD) versions, specialty logs (such as Schlumberger's cyberlook, formation microscanners and dipmeter logs), measured-while-drilling (MWD) and logged-while-drilling (LWD) logs (in color, when available). Provide 5-inch scale logs when 2-inch scale logs are unavailable.
20. paper copy of final composite mud or lithology log and report, with lithology display, oil and gas show indicators, and cuttings descriptions (in color, when available).
21. a digital version of well logs in LAS format on IBM format floppy disks, Zip100 disk, CD or DVD, and a digital version of final directional surveys in ASCII format (other formats may be acceptable upon agreement with the Division of Oil and Gas).
22. Paper and digital (if available) copies of all well data and reports including, but not limited to, paleontology, palynology, petrography (including point-count analyses), X-ray diffraction analyses, SEM micrographs, thermal maturity, vitrinite reflectance, rock eval pyrolysis, geochronology, fission track analyses, fluid inclusion analyses, Mercury injection capillary pressure analyses, chemical analyses (EPMA, XRF, ICP, etc.), isotope analyses, water chemistry, burial and temperature history analyses, strain analyses and acoustic analyses.
23. all final reports of velocity, checkshot or VSP surveys (an ASCII format digital version of the above data shall also be submitted), indicate "none" in your response to this request if no velocity, checkshot or VSP surveys were undertaken. Submission of velocity, checkshot, and VSP surveys are always required by DNR under the operator surface-use permit obligations.
24. paper and digital copies of all coalbed core, gas and water quality reports including lab analyses of core lithology, coal rank, vitrinite reflectance, maceral composition, TOC,

ash, sulfer and BTU content, moisture content, cleating, adsorption/desorption data, residual gas measurements, porosity and permeability analyses, core photos, if available.

All material should be either hand-carried by bonded courier or mailed by registered mail to:

Kristin Dirks, Geologist
Dept. of Natural Resources-Div. of Oil and Gas
State of Alaska
550 W. 7th Avenue, Suite 800
Anchorage, AK 99501-3510

Telephone: (907)269-8769
Fax: (907)269-8942
Email: kristin_dirks@dnr.state.ak.us

The state may also require the lessee to submit additional data in accordance with the applicable statutes and regulations in effect at the time of the drilling and completion of the well.

Any data submitted to the state by the lessee in connection with this lease will be available at all times for use by the state and its agents. The state will keep information confidential as provided in AS 38.05.035(a)(9) and its applicable regulations. In accordance with AS 38.05.035(a)(9)(c), in order for geological, geophysical and engineering data submitted under the lease agreement named above to be held confidential, the lessee must request confidentiality at the time the data is submitted by indicating "CONFIDENTIAL" on all confidential data items.

This action does not eliminate the need to file all data normally filed with the Alaska Oil and Gas Conservation Commission (AOGCC) under their permit requirements.