PRUDHOE BAY UNIT

APPLICATION TO COMBINE THE NIAKUK AND WEST NIAKUK PARTICIPATING AREAS INTO THE COMBINED NIAKUK PARTICIPATING AREA

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

December 5, 2007

TABLE OF CONTENTS

I. APPLICATION AND RESULTS 3

II. DISCUSSION OF THE DECISION CRITERIA 4

A. 11 AAC 83.303(B) CRITERIA DISCUSSION 4

1. PRIOR EXPLORATION AND DEVELOPMENT ACTIVITIES AND THE GEOLOGICAL AND ENGINEERING CHARACTERISTICS OF THE RESERVOIR 4
2. BPXA'S PLANS OF DEVELOPMENT 7
3. THE ECONOMIC COSTS AND BENEFITS TO THE STATE 7
4. THE ENVIRONMENTAL COSTS AND BENEFITS 15

B. 11 AAC 83.303(A) CRITERIA DISCUSSION 16

1. PROMOTE THE CONSERVATION OF ALL NATURAL RESOURCES AND PREVENTION OF ECONOMIC AND PHYSICAL WASTE 16
2. PROVIDE FOR THE PROTECTION OF ALL PARTIES OF INTEREST, INCLUDING THE STATE 16

III. FINDINGS AND DECISION 18

Attachment #1 - CNPA and PBU Expansions and Contractions
Attachment #2 - Map of the CNPA
Attachment #3 - Proposed CNPA Tract Description, Allocation, and Ownership Schedule
Attachment #4 - CNPA Data Submittal Requirement
Attachment #5 – Objection to formation of CNPA

I. APPLICATION AND RESULTS

BP Exploration (Alaska) Inc. (BPXA), operator of the Niakuk Participating Area (NPA) and the West Niakuk Participating Area (WNPA), on behalf of itself and the other Working Interest Owners (WIO), including Chevron U.S.A. Inc., ConocoPhillips Alaska Inc. (CPAI), and ExxonMobil Alaska Production Inc. (Exxon), applied (Application) on May 5, 2005, to the State of Alaska, Department of Natural Resources (DNR), Division of Oil and Gas (Division) to combine the NPA and WNPA and contract the Prudhoe Bay Unit (PBU). The NPA was formed in 1994 and the WNPA was formed in 1997. The Application proposes a single Combined Niakuk Participating Area (CNPA). Forest Oil Corporation was a WIO at the time the Application was submitted, but has subsequently sold its interest.

The Application responds to the Division's November 17, 1997, interim decision approving the "Fourth Expansion of the Unit Area, First Expansion of the Participating Area and Formation of the WNPA." That interim decision approved the formation of the WNPA as a "temporary solution," and set March 31, 1998, for the Greater Niakuk Area owners to submit a "final combined (WNPA and NPA) application." The Application is the "final combined (WNPA and NPA) application," as contemplated in the interim decision. The Application and this Findings and Decision (Decision) have been delayed since 1998 for various reasons, including the need to complete additional appraisal drilling and equity negotiations among WIOs, to exchange additional information, and to conduct and complete negotiations between the Division and WIOs.

The key results of this Decision are as follows.

- Field cost allowance refunds and amended royalty reports
  The WIOs shall pay the State for certain field costs previously deducted from the State's royalty share of NPA and WNPA production, plus interest, under the retroactive, revised production allocations established under this Decision. This Decision also establishes the percentage of CNPA production ineligible for future field cost deductions. The WIOs shall file amended royalty reports to account for the prior production that is subject to field cost refunds.

- CNPA and PBU boundaries established
  The NPA, WNPA, and the PBU are conformed to an approved CNPA and PBU boundary and Section 21 NE ¼, N ½ SE ¼ of ADL 34626, will automatically contract out of the CNPA and PBU if a well is not drilled, tested, and certified as capable of production in paying quantities in that area by January 1, 2011.

- Final tract allocations established
  NPA and WNPA tract allocations approved under the interim decision are revised retroactively for production previously allocated to the

northern halves of ADLs 34625 and 34626. CNPA tract allocations are established.

- September 1980 Prudhoe Bay Unit Royalty Settlement Agreement (1980 RSA)
  The 1980 RSA will not apply to production from the northern halves of ADLs 34625 and 34626, effective upon approval of this Decision and retroactive to November 1, 1996.

II. DISCUSSION OF THE DECISION CRITERIA

The DNR commissioner (Commissioner) reviews unit-related applications 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 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 is set out directly below, followed by a discussion of the subsection (a) criteria.

A. 11 AAC 83.303(b) criteria discussion

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

The proposed CNPA boundary is based on the known extent of the Kuparuk River Formation (Kuparuk) Reservoir boundaries using geologic, geophysical, and reservoir engineering (G&G) data. G&G and other technical data submitted in support of the Application included the following: type logs, paper and digital copies of the top structure, net pay and oil pore foot maps for the Kuparuk, interpreted seismic lines, structural cross sections through the Niakuk segments, digital log data, a spreadsheet of log tops and sub-zones, 3-D seismic dataset, detailed discussion of the Niakuk geologic and reservoir models, discussion of the 2005 original oil in place (OOIP) map, detailed discussion of the petrophysical log model used for Niakuk segments 1, 3, 5 and 2, and a discussion of the development of the NPA and WNPA. The Division will hold these data confidential under AS 38.05.035(a)(9)(C) and 11 AAC 96.220.

In the 1970s and early 1980s, exploration north of the Prudhoe Bay oil field focused on the Permo-Triassic Ivishak sandstone, the same target found at Prudhoe Bay. It wasn't until the late 1980s that exploration ventures considered reservoir targets other than the Ivishak sandstone as potential developments. One of the primary targets became the Kuparuk.

During lower Cretaceous time, deposition on the present day North Slope changed from a relatively passive margin with sediments sourced from the north to an extensional rift basin margin in which sediments were sourced from faulted, rift margin shoulders to the south. A regionally extensive unconformity called the Lower Cretaceous Unconformity (LCU) marks the uplift and subsequent erosion of Lower Cretaceous to pre-Devonian basement rocks across the North Slope. Secondary

faults within the rift margin contributed sediment as well as impacted local sediment dispersal. Sediment was preserved in local depo-centers off the bounding highs.

The ancestral Prudhoe High, location of the super giant Prudhoe Bay oil field, is one of the primary sources for Lower Cretaceous Kuparuk deposition at Niakuk.

The Kuparuk sediments at Niakuk are approximately the age of the Lower Cretaceous Kuparuk River Formation C sandstones at Kuparuk River Field, located 28 miles to the west. Niakuk stratigraphy is complex. The stratigraphy in combination with minor faults contributes to the formation of two separate accumulations in four segments that have been developed over the past 13 years. The Kuparuk is overlain by minor Kalubik shales and a thick succession of highly radioactive shale (HRZ). The Kuparuk occurs above the LCU that erodes into progressively older formations on local horst blocks and to the east. In general, the Kuparuk at Niakuk lies unconformably above the LCU, which eroded into shales of the Jurassic Miluveach or Kingak Formations.

The Niakuk Oil Pool is defined as the accumulation of hydrocarbons that is found in and is correlative with the interval from 12,318 feet MD (-9,351 feet TVDss) to 12,942 feet MD (-9,842 feet TVDss) in the Niakuk #6 well. The CNPA is a combination structural/stratigraphic trap. It is bound to the south by a major normal fault zone, the Niakuk bounding fault which juxtaposes Kuparuk on the northern, down-thrown side against Lisburne carbonates on the south side of the fault. To the north, east, and west, reservoir quality degrades to siltstone. Structural dip to the east in Segment 2 also contributes to trapping. There are three segments in the western accumulation and one segment in the eastern accumulation. These segments are bounded by minor faulting on the north and south sides and each segment has a unique stratigraphy. The two accumulations have different oil-water contacts.

Early exploration wells north of Prudhoe Bay Field include the Niakuk #1,1A, 2, 2A, 3, 4, 5 and 6 wells, the Gull Island #1 well and the Pt. McIntyre #1 and #2 wells. These early wells, while targeting deeper formations, penetrated a section of the Kuparuk that was very different depositionally from the Kuparuk located in the Kuparuk River Field. The Kuparuk interval north of Prudhoe Bay Field is depositionally complex, exhibits structurally controlled thickening and thinning and is segmented by minor faults as evidenced by various oil-water contacts. The various oil water contacts define segments. Segments 1, 3, and 5 occur in the western area and Segment 2 occurs in the eastern area of the CNPA.

The Sohio Niakuk #1 and #1A wells, completed in 1975 and 1976, respectively, encountered hydrocarbons in the Kuparuk interval, but the wells were not tested. Core in the Kuparuk at Niakuk #1A confirmed oil shows that were indicated on electric logs and a mudlog. Additional drilling of the Sohio Niakuk #2 and #2A wells in 1976 and 1977 confirmed fair hydrocarbon shows in the Kuparuk based on mudlogs, but also illustrated limits on reservoir quality and pay. In 1977 Gulf Oil Co. drilled the Point McIntyre #1 and #2 wells approximately 8.5 miles west of the Niakuk wells. They drilled straight through mudlog shows that indicated fair oil shows in the Kuparuk in order to evaluate the Ivishak sandstone, which was wet. The wells were plugged and abandoned that same year. Geographically between the early Point McIntyre and Niakuk wells, ARCO drilled the Gull Island #1 well in 1976. The Kuparuk interval found in Gull Island #1 contained a low net/gross interval that precluded any testing. The Niakuk #3 well was drilled and completed in 1979. The top Kuparuk was located down structure at -9301TVDss. SWC's indicated poor shows in the Kuparuk. The well was plugged and abandoned in April 1980. Niakuk #4 completed drilling in 1985. Niakuk #4 is

completely missing the Kuparuk as it is located at the crest of a horst block. The LCU scours down into the Jurassic Kingak shales at this location. This suggested a more complex depositional history for the Kuparuk in this area than had previously been thought. BPXA's Niakuk #5, the discovery well for the Niakuk pool, was completed on April 18, 1985. It was cored and tested oil at 1,800 BOPD in the Kuparuk. The Niakuk pool was further delineated with Niakuk #6, which was drilled and cored in the Kuparuk in 1986.

Production from the NPA commenced in April 1994 from five production wells (NK-18, NK-20, NK-22, NK-23 and NK-26) in the eastern area and two production wells (NK-10 and NK-12A) in the western area. Production from the WNPA started as a tract operation with production from NK-27 (West Niakuk 1) in April 1995. West Niakuk is an extension of the western segment(s) that were defined in the NPA. To date there are a total of 19 producers and eight injectors (not counting ST's and PB's) drilled from the Heald Point NK DS. There is one producer L5-34 drilled from the Lisburne L5 drillsite. All production has been from the Kuparuk until recently.

Initial estimates of rock properties based on the early exploration wells (Niakuk 1, 1A, 2, 2A, 5 and 6) are as follows:

Segment 1	Porosity	Permeability	Net/Gross	Oil Saturation
Zone 3	24.4%	6-1250md	1.0	66%
Zone 4	15.2%	6-1250md	.95	75%
Segment 2				
Zone D	19.5%	1-1169md	.87	67%
Zone F	23.0%	1-3008md	.98	79%

Fluid properties based on reservoir fluid samples from Niakuk 5 located in the eastern segment include the following:

- Initial reservoir pressure of 4,461 psia at 8,900' TVD subsea.
- Bubble-point pressure is estimated at 4,200psi (up from an initial estimate of 3,835 psia in 1993).
- Initial Reservoir temperature ranged from 179 to 182 degrees F.
- Oil gravity measures 24.9o API, range between 20-30 API.
- Viscosity of 1.4 centipoise
- Oil formation volume factor (Boi) is 1.31 RB/STB at bubble point pressure.

The oil-water contact in the West Niakuk (Segment 1) is -9,240TVDss, in the West Niakuk Platform (Segments 3 and 5) it is -9,285 TVDss and in the East Niakuk area (Segment 2) it is –9,535TVDss. Estimated OOIP in the Niakuk Oil Pool is approximately 310MMSTB.

BPXA has submitted data that supports the mapped CNPA as being underlain by hydrocarbons. It has been producing hydrocarbons in paying quantities since 1994. The Division's evaluation of the subsurface geology supports the configuration of the proposed CNPA.

2. BPXA's Plans of Development

BPXA has submitted plans of development for the CNPA 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 pending CNPA. That approval remains in effect.

3. The Economic Costs and Benefits to the State

3.1-Tract Allocation Schedule

Attachment #3 is the proposed CNPA Tract Description, Allocation, and Ownership Schedule included in the Application. The "tract participation percentage," column 12 of attachment #3, is the proposed CNPA production allocation by tract. The tract participation percentages are calculated from known G&G data and are based on OOIP. To account for lands outside the original PBU, and not subject to a field cost deduction from the state's share of royalty oil production, BPXA proposed that 6.79 percent and 5.58 percent of production from the NPA and WNPA be allocated to the northern halves of ADLs 34625 and 34626, respectively. In a January 31, 2007, letter, BPXA revised those percentages and proposed that 7.474 percent and 5.584 percent of production from the NPA and WNPA be allocated to the northern halves of ADLs 34625 and 34626, respectively.

Allocation of 7.474 percent of NPA production to the northern half of ADL 34625 and 5.584 percent of WNPA production to the northern half of ADL 34626 is approved. These allocations shall apply retroactively from January 1, 2008; 1) to January 1, 2000 for CPAI and BPXA; 2) to November 1, 1996 for Exxon, and; 3) for other NPA and WNPA minority interest owners to the date they joined the NPA and WNPA. These retroactive allocations replace the tract allocations approved in the 1997 interim decision for the northern halves of ADLs 34625 and 34626. BPXA is not required to retroactively re-file monthly operator reports for the NPA and WNPA.

Effective January 1, 2008, the sum of these retroactive NPA and WNPA allocations, or 13.058 percent of CNPA production, must be allocated to the northern halves of ADLs 34625 and 34626.

When the Application was submitted, BPXA owned 26.355356 percent, Chevron owned 1.16 percent, Exxon owned 36.395491 percent, CPAI owned 36.069385 percent, and Forest owned 0.019768 percent of the production from the RPA. Effective September 1, 2006, Forest's ownership was assigned to BPXA, CPAI, and Exxon. The following revised Ownership currently applies to the CNPA: BPXA-26.360567%, CPAI – 36.076746%, Exxon – 36.402687%, and Chevron – 1.16%. Within 30 days of this Decision, BPXA shall submit a revised CNPA Tract Description, Allocation, and Ownership Schedule that reflects the recent CNPA ownership change.

3.2-Field Costs

Refunds due to the state for field costs previously deducted from the state's royalty share of NPA and WNPA total production are retroactive to January 1, 2000, for CPAI and BPXA and to November 1, 1996, for Exxon. Refunds from other PBU minority WIOs are retroactive to the date they joined the NPA and WNPA. CPAI's and BPXA's retroactive payment obligations have been adjusted based on the 2001 Royalty Settlement Agreements between the State and BPXA and CPAI's predecessor settling all royalty value claims for the period 1993 through 1999. Table 1, below, lists the NPA and WNPA lessees and their ownership percentages since November 1, 1996.

The 1980 RSA will not apply to production from the northern halves of ADLs 34625 and 34626 effective upon approval of this Decision and retroactive to November 1, 1996.

Table 1

Period	NPA Lessees	Lessee's %	WNPA Lessees	Lessee's %	Comment
11/1/1996 - 3/31/2000	BPXA	100	ARCO AK	50	INITIAL
			EXXON	50	
4/1/2000 - 4/30/2000	BPXA	100	ARCO AK	50	Name Change: Exxon to ExxMob
			EXXMOB	50	
5/1/2000 - 6/30/2000	BPXA	100	EXXMOB	50	Name Change: ARCO AK to PHILLAK
			PHILLAK	50	
7/1/2000 - 1/31/2001	BPXA	26.66467	BPXA	26.66467	REALIGNMENT
	EXXMOB	35.82283	EXXMOB	35.82283	
	FORCE	0.02	FORCE	0.02	
	MOBIL AKEP	0.9998	MOBIL AKEP	0.9998	
	PHILLAK	36.4927	PHILLAK	36.4927	
2/1/2001 - 6/30/2001	BPXA	26.66467	BPXA	26.66467	Name Change: FORCE to FOREST
	EXXMOB	35.82283	EXXMOB	35.82283	
	FOREST	0.02	FOREST	0.02	
	MOBIL AKEP	0.9998	MOBIL AKEP	0.9998	
	PHILLAK	36.4927	PHILLAK	36.4927	
7/1/2001 - 9/30/2002	BPXA	26.66467	BPXA	26.66467	Exxon/Mobil Name Changes/Assignments
	EXXMOBAK	36.82263	EXXMOBAK	36.82263	
	FOREST	0.02	FOREST	0.02	
	PHILLAK	36.4927	PHILLAK	36.4927	
10/1/2002 - 10/31/2002	BPXA	26.66467	BPXA	26.66467	Name Change: PhillAk to ConPhillAk
	CONPHILLAK	36.4927	CONPHILLAK	36.4927	
	EXXMOBAK	36.82263	EXXMOBAK	36.82263	
	FOREST	0.02	FOREST	0.02	

Table 1 -continued

Period	NPA Lessees	Lessee's %	WNPA Lessees	Lessee's %	Comment
11/1/2002 - 8/31/2006	BPXA	26.355356	BPXA	26.355356	PBU Super Alignment
	CHEVRON	1.16	CHEVRON	1.16	
	CONPHILLAK	36.069385	CONPHILLAK	36.069385	
	EXXMOBAK	36.395491	EXXMOBAK	36.395491	
	FOREST	0.019768	FOREST	0.019768	
9/1/2006 - present	BPXA	26.360567	BPXA	26.360567	ASSIGNMENT: FOREST to BPXA / CONPHILLAK / EXXMOBAK
	CHEVRON	1.16	CHEVRON	1.16	
	CONPHILLAK	36.076746	CONPHILLAK	36.076746	
	EXXMOBAK	36.402687	EXXMOBAK	36.402687	

No later than March 31, 2008, each WIO shall file amended royalty returns electronically with the state in the same manner as it filed its original royalty returns. The WIOs shall file amended returns for the first production month and for each succeeding production month for which royalties were not originally filed in accordance with the terms of this Decision. The WIOs shall use selling arrangement code 207002A001 to account for reimbursement to the state the portion of gross monthly production volume not entitled to a field cost deduction. Contemporaneously, each WIO shall pay the field cost refund amount due by wire transfer, made in the same manner that it made the initial royalty payments. The amount due for each production month must include interest on the principal amount due to the state for the month. The interest must be calculated from the date that the original royalty report was due until the date of refund payment under each WIO's royalty settlement agreement with the state. Effective with the production month of January 1, 2008, BPXA, as operator, shall file operator reports (O1) and each WIO shall file royalty reports (A1) using the new accounting unit code PBCN for the CNPA.

3.3 Participating Area Boundary

The CNPA previously consisted of two separate PAs, the NPA and WNPA, which were established partially based on lease lines that reflected prior working interest ownership. Ownership interests have subsequently been aligned and the extent of the reservoir has been further defined through additional field development. The alignment of interests and expanded knowledge of the reservoir boundaries justifies combining the two separate PAs into a single combined PA. 11 AAC 83.351(b) provides that "[a] separate participating area must be established ... for each reservoir delineated, except that with the consent of the commissioner and all working interest owners, any two or more reservoirs or participating areas within the unit may be combined into one participating area . . . ."

The NPA, WNPA, and the PBU will be conformed to the approved CNPA and revised PBU boundaries as shown and described in Attachments 1, 2, and 3. The approved CNPA encompasses the reasonably known reservoir limits of the Kuparak sufficient to justify development and production. The boundaries were established based on the known extent of the reservoir boundary using G&G data. 11 AAC 83.351(a) provides that a PA may "include only the land reasonably known to be underlain by hydrocarbons and reasonably known or reasonably estimated . . . to be capable of producing or contributing to production of hydrocarbons in paying quantities." Similarly, 11 AAC 83.351(c) provides that a PA must "exclude acreage reasonably proven through the use of geological, geophysical, or engineering data to be incapable of producing hydrocarbons in paying quantities, subject to approval by the commissioner." Paying quantities is defined by 11 AAC 83.395(4) to mean:

> Quantities sufficient to yield a return in excess of operating costs, even if drilling and equipment costs may never be repaid and the undertaking as a whole may ultimately result in a loss; quantities are insufficient to yield a return in excess of operating costs unless those quantities, not considering costs of transportation and marketing, will produce sufficient revenue to induce a prudent operator to produce those quantities.

BPXA provided the Division with confidential G&G data indicating that paying quantities may exist in Section 21 NE ¼, N ½ SE ¼ of ADL 34626 (designated area). The designated area has no well and is included in the CNPA based on the existing G&G data and contingent on the following:

- Three years from the effective date of this Decision, BPXA shall drill a well into the designated area that penetrates the Kuparak River sandstone.

- If the well is tested, BPXA shall timely provide the Division with a status report of operations, well test, core, logging, and other drilling results and data sufficient for the Division to make a paying quantities determination under 11 ACC 83.361.

Notwithstanding the provisions of 11 AAC 83.356 regarding notice and hearing and an opportunity to be heard, if BPXA does not complete the above obligations, or if the well does not have paying quantities as determined by the Division under 11 ACC 83.361, the designated area will automatically contract out of the CNPA and PBU. The WIOs have agreed to contract this area out of the CNPA if a well is not drilled three years from the effective date of this Decision. If the designated area contracts out of the CNPA and PBU, BPXA shall timely file the following with the Division:

- revised CNPA and PBU maps contracting Section 21 NE ¼, N ½ SE ¼ of ADL No. 34626 out of the CNPA and PBU; and

- revised allocation of OOIP attributable to each tract in the CNPA, including the OOIP attributable to the northern halves of ADLs 34625 and 34626. These revised allocations are subject to Division review and approval under 11 AAC 83.371.

3.4-Facility Sharing, Production Allocation, and Metering

The CNPA will be developed from the Heald Point drill pad where there are six mini-modules including two production manifold skids accommodating 19 producers and eight injectors (including two Lisburne-Alapah wells). This leaves available space for several additional wells. Well L5-34 was drilled from the Lisburne L5 drill site into the CNPA and shares drillsite facilities with other Lisburne wells at that location. CNPA production will flow onto shared facilities at the Lisburne Production Center (LPC), resulting in surface commingling of CNPA production with Lisburne, Point McIntyre, Stump Island, Kuparak, and West Beach production. The CNPA will receive water injection from the LPC and lift gas from the Lisburne high-pressure gas injection system at the Lisburne L5 drillsite. CNPA was converted back to seawater injection as part of a larger Greater Point McIntyre water optimization project so that only produced water is injected. Infrastructure support facilities--camp, water, shop, roads, bridges, airstrip, etc.--will be shared with the Lisburne Participating Area and Initial Participating Area. CNPA production will be constrained by the gas and water handling capacity at the LPC. This facility and infrastructure sharing is expected to lower development and operating costs, increase ultimate recovery, and reduce waste.

In a September 26, 2005, letter BPXA amended the Application by submitting draft Niakuk Special Supplemental Provisions (draft NSSP) to the Prudhoe Bay Unit Operating Agreement as Attachment #12. The draft NSSP establishes certain provisions for CNPA wells using LPC facilities. BPXA further indicated in the September 26, 2005, letter, that revisions to the draft NSSP were under way. BPXA shall submit a final, complete, and signed NSSP to the Division within 90 days of this Decision. The final NSSP must be substantively consistent with the draft, include all attachments, and highlight any changes from the draft version provided with the Application.

In a September 29, 2005, letter BPXA indicated that the third and fourth amendments to the Lisburne Special Supplemental Provisions (LSSP) provide for CNPA use of the LPC and sharing of other Lisburne equipment and provided a copy of those amendments. Further, in a February 24, 2006, letter BPXA indicated that Lisburne PA owners had approved the sharing of Lisburne equipment with the greater Niakuk area owners and had approved treatment of the greater Niakuk area as a sharing participating area under Section 53.02 of the LSSP. BPXA also provided a copy of the LSSP as an attachment to the September 29, 2005, letter. This approval is based, in part, on the third and fourth amendments to the LSSP providing for CNPA use of the LPC and sharing of other Lisburne equipment, and the PBU and Lisburne owners approving the sharing of Lisburne equipment with the CNPA owners and treating the CNPA as a sharing participating area under terms in the third and fourth amendments to the LSSP. If the CNPA or Lisburne owners have made any changes to the third and fourth amendments to the LSSP or Section 53.02 of the LSSP since September 29, 2005, a full description and documentation of the changes must be provided to the Division within 90 days of this Decision.

CNPA 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. 329A, dated June 4, 1996, 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.

NGLs 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 CNPA and proposed Raven PA. 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:

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 planned Raven Participating Area and the 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.

3.5-Gas Disposition

The interim CNPA Initial POD indicated that Niakuk-produced gas (except gas extracted as NGLs and shipped through TAPS) would be, prior to gas sales, used or consumed for unit operations, or injected into another formation underlying the PBU Area. The Division recognizes that there may be more gas produced beyond that used for unit operations and approves injecting this excess gas into another formation underlying the unit area or to extract NGLs and blend with crude oil for shipment through TAPS. However, any residue gas from the CNPA 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 CNPA injected into another formation underlying the unit area will be treated as indigenous natural gas for royalty reporting purposes and WIOs will be responsible for royalty payments when the gas is ultimately sold. Any residue gas injected from the CNPA 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 CNPA gas injection into another formation because it would be burdensome for the Division and the WIOs to track and report the relatively small amount of gas produced from the CNPA reservoirs.

BPXA has also indicated that CNPA gas extracted as NGLs and blended with crude oil for shipment through TAPS will be processed through the Lisburne NGL plant. Therefore, extracting NGLs at the Lisburne NGL plant from CNPA-produced gas is approved and all NGLs manufactured at the Lisburne NGL plant from CNPA-produced gas must be accounted for and reported as CNPA NGLs.

3.6 Summary of Economic Costs and Benefits to the State

The CNPA will result in both short-term and long-term economic benefits to the state. Continued development and production from the CNPA 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 the CNPA.

This Decision provides for refund to the state of field costs previously deducted from the state's share of royalty oil production attributable to northern halves of ADLs 34625 and 34626. In addition, this decision provides for elimination of future field cost deductions from the state's share of royalty oil production attributable to these areas. This increases net royalty revenue to the state attributable to oil production from the CNPA, and attributable to past production from the NPA and WNPA.

While much of the reservoir development has already been completed, the WIOs have proposed adequate plans to develop the remaining CNPA reserves.

The economic benefits of forming the CNPA outweigh the costs. Therefore, the Division's evaluation of the section .303(b)(5) criteria supports approval of the Application.

4. The Environmental Costs and Benefits

The approval of the CNPA itself has no environmental impact. Approval of the CNPA is an administrative action that does not convey any authority to conduct any operations on the surface within the unit area. 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.

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 must obtain permits from various agencies before drilling a well or wells or initiating development activities to further develop known reservoirs within the CNPA. PBU leases 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 operator must also obtain the Division's approval of a plan of operations before performing 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 NPA and WNPA and is independent of subsurface boundaries. Consolidation of the NPA and WNPA into the CNPA has no effect on the continued compliance under the existing PBU Plan of Operations.

There has been production from the NPA and WNPA since approximately 1994 and the CNPA reservoirs are now in the later stages of development and production. No significant surface facility expansions are anticipated at this time. The CNPA will continue to provide access to existing LPC facilities for consolidated development of the Kuparak reservoirs. Unnecessary duplication of development efforts on and under the surface has been and will continue to be avoided. Activity will continue to affect habitat and subsistence activity less than if development occurred on individual leases. Continued development activity is not expected to significantly impact bird, fish, and mammal populations.

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

B. 11 AAC 83.303(a) Criteria Discussion

1. Promote the Conservation of all Natural Resources and Prevention of Economic and Physical Waste

The CNPA owners have developed the Kuparak reservoirs in a way that prevents economic and physical waste and promotes the conservation of resources through unitized rather than lease-by-lease development. Mitigation measures are in place to promote conservation and prevent waste and future development should continue in the same fashion.

The CNPA will share production facilities and support infrastructure with the Lisburne, Point McIntyre, and initial PBU PAs. As discussed above, a unit plan of operations is currently in place for the NPA and WNPA. Consolidation of the NPA and WNPA into the CNPA has no effect on the existing plan of operations. Compliance with the plan of operations should conserve and prevent economic and physical waste of surface resources.

The CNPA provides for efficient, integrated development of the Kuparak reservoirs. The CNPA promotes efficient development of the reservoir, efficient well spacing, and reasonable operating and reservoir management strategies. The CNPA allows 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 CNPA in combination with more productive leases. The CNPA will allow more optimal pressure maintenance and secondary recovery through a joint, unitized effort of the WIOs. Maximizing oil and gas recovery results in a more optimal use of the resource and minimizes economic and physical waste.

Formation of the CNPA should reduce costs and environmental impacts associated with development of the Kuparak reservoir within this area of the PBU, thereby conserving resources, preventing economic and physical waste, expediting development of reserves, and promoting more optimal ultimate recovery of oil and gas from the CNPA. 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 CNPA protects the economic interests of the state and will be more likely to maximize hydrocarbon recovery and revenue to the state. Formation of the CNPA continues and 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 CNPA 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 18, 2006, the Division received a letter from Mr. Ray Givens, attorney for the Oenga heirs who own surface rights to Heald Point. The Oenga heirs assert that their Heald Point surface lease

with BPXA authorizes production from Niakuk, but not from West Niakuk. The letter, which is included as Attachment #5 to this Decision, asked that the Division:

1. take any and all action within its jurisdiction to halt the production of oil and gas from West Niakuk PA through Heald Point until this trespass matter is resolved;
2. delay the consolidation of the Niakuk PA and West Niakuk PA until this matter is resolved;
3. take any and all action within its jurisdiction to halt the production of oil and gas from West Niakuk PA through Heald Point until BPXA, as lessee of BIA Lease #F-89-01, and the other West Niakuk interest holders can provide the Department with concurrence from all parties with an ownership interest in the Heald Point property that there exists the requisite legal authority to produce oil and gas from West Niakuk through the Heald Point facility; and
4. Delay the consolidation of the Niakuk PA and West Niakuk PA until this concurrence is provided.

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

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

The Division will not further delay its CNPA formation decision because of these requests. This decision deals with subsurface issue surrounding the establishment of the consolidated PA. 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.

III. Findings and Decision

1. Under 11 AAC 83.303, I approve the Application to form the CNPA effective January 1, 2008, subject to the terms and conditions set out in this Decision.

2. The NPA, WNPA, and the PBU are conformed to the approved CNPA and revised PBU boundaries as shown and described in Attachments 1, 2, and 3. The approved CNPA encompasses the reasonably known reservoir limits of the Kuparak River formation sufficient to justify development and production.

3. Section 21 NE ¼, N ½ SE ¼ of ADL 34626, as shown and described in Attachments 1, 2, and 3, is included in the CNPA contingent on the drilling, testing, and certification of a well that penetrates the Kuparak River Sandstone on or before three years from the effective date of this decision, and as provided in section II A 3.3 of this Decision.

4. BPXA shall file operator (O1) reports and each WIO shall file royalty reports (A1) using the new accounting unit code of PBCN for the CNPA. BPXA and the other WIOs shall reference this account code on the monthly operator and royalty reports submitted to the Division for CNPA production. The accounting code becomes effective on the first day of the month following this approval. In the case where production from CNPA Kuparak Reservoir is commingled downhole with production from the proposed Raven Reservoir, such as is the case with NK-43, only the portion of production allocated to the CNPA Kuparak Reservoir must be referenced to the new accounting unit code of PBCN on the monthly operator and royalty reports submitted to the Division for CNPA production. The Raven Reservoir portion must be appropriately allocated to its approved accounting code on the Raven monthly operator and royalty reports submitted to the Division.

5. BPXA shall conduct diligent exploration, delineation, and production of the reservoirs underlying the approved CNPA 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.

6. The formation of the CNPA divides costs and allocates produced hydrocarbons in a manner currently acceptable to all affected WIOs and in accordance with the terms of the November 17, 1997, interim decision and applicable state regulations, including 11 AAC 83.351(a) and 11 AAC 83.371(a). 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 allocation of production and costs for the tracts within the CNPA as set out in Attachment #3, but subject to a revision of the ownership schedule as described in section II A 3.1 of this Decision. Within 30 days of this Decision, BPXA shall submit on behalf of the WIOs, a revised CNPA Tract Description, Allocation, and Ownership Schedule that reflects the transfer of Forest's interest as described in section II A 3.1 of this decision.

7. Allocation of 7.474 percent and 5.584 percent of production from the NPA and WNPA to the northern halves of ADLs 34625 and 34626, respectively is approved, retroactive from the effective date of this Decision to the retroactive dates set out in paragraph 9.

8. Field costs must not be deducted from the state's share of royalty oil production attributable to the northern halves of ADLs 34625 and 34626, areas outside the original PBU, and field costs previously deducted from this production must be refunded to the state, plus interest, retroactive from the effective date of this Decision to the retroactive dates set out in paragraph 9.

9. Refunds of field costs previously deducted from the state's royalty share of NPA and WNPA production are retroactive to January 1, 2000, for CPAI and BPXA and to November 1, 1996, for Exxon. Refunds from other minority WIOs are retroactive to the dates they joined the CNPA and WNPA.

10. Effective January 1, 2008, allocation of 13.058 percent of CNPA production to the northern halves of ADLs 34625 and 34626 is approved.

11. The 1980 RSA will not apply to production from the northern halves of ADLs 34625 and 34626, effective upon approval of this Decision and retroactive to November 1, 1996.

12. No later than March 31, 2008, each WIO shall file amended royalty returns electronically with the state in the same manner as it filed its original royalty returns. The WIOs shall file amended returns for the first production month and for each succeeding production month for which royalties were not originally filed in accordance with the terms of this Decision. The WIOs shall use selling arrangement code 207002A001 to account for reimbursement to the state the portion of gross monthly production volume not entitled to a field cost deduction. Contemporaneously, each WIO shall pay the field cost refund amount due by wire transfer, made in the same manner that it made the initial royalty payments. The amount due for each production month must include interest on the principal amount due to the state for the month. The interest must be calculated from the date that the original royalty report was due until the date of refund payment under each WIO's royalty settlement agreement with the state. Effective with the production month of January 1, 2008, BPXA, as operator, shall file operator reports (O1) and each WIO shall file royalty reports (A1) using the new accounting unit code PBCN for the CNPA.

13. CNPA production may be commingled with other PBU production in PBU surface facilities before custody transfer. The terms for use of those facilities are amendments to the PBU operating agreement and are set out in the NSSP and the third and fourth amendments to the LSSP. This Decision describes BPXA's submittals and representations regarding these amendments. BPXA shall submit a final NSSP subject to the terms and conditions set out in this Decision.

14. CNPA production shall be allocated and metered according to terms and conditions set out in this Decision.

15. The Division recognizes that there may be more gas produced from the CNPA beyond that used for unit operations and approves injecting this excess gas into another formation underlying the unit area and extracting and blending NGLs with crude oil for shipment through TAPS subject to terms and conditions set out in this Decision.

16. BPXA has also represented that CNPA gas extracted as NGLs and blended with crude oil for shipment through TAPS will be processed through the Lisburne NGL plant. Therefore, extracting NGLs at the Lisburne NGL plant from CNPA-produced gas is approved and all NGLs manufactured at the Lisburne NGL plant from CNPA-produced gas must be accounted for and reported as CNPA NGLs subject to the terms and conditions set out in this Decision.

17. CNPA data submittal requirements are listed in Attachment #4. BPXA shall provide this data to the Division, to the extent not already provided, in support of any future CNPA modifications or future CNPA PODs.

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.

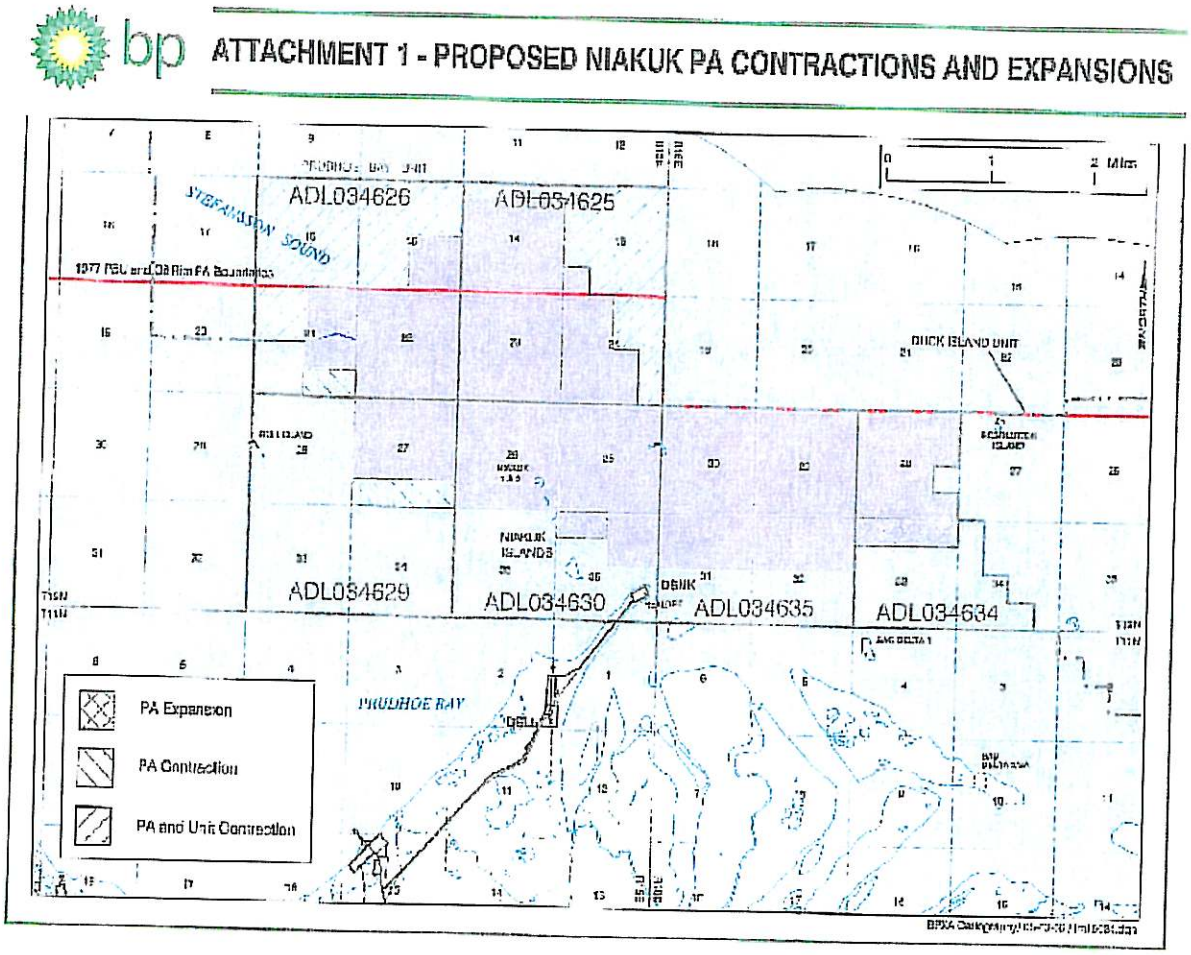
Kevin Banks, Acting Director

December 5, 2007
Date

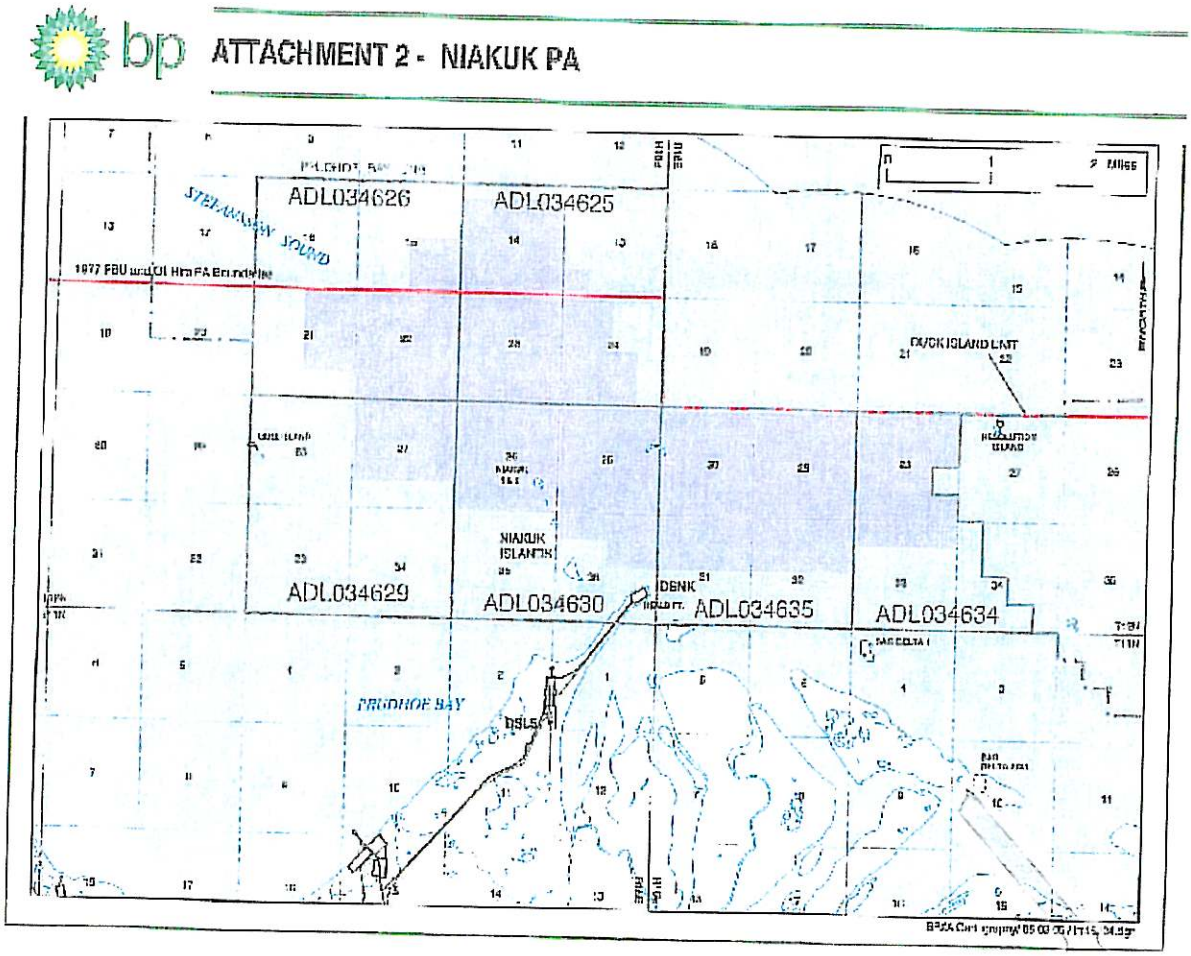
Attachments:

Attachment #1 - CNPA and PBU Expansions and Contractions
Attachment #2 - Map of the CNPA
Attachment #3 - Proposed CNPA Tract Description, Allocation, and Ownership Schedule
Attachment #4 - CNPA Data Submittal Requirement
Attachment #5 – Objection to formation of CNPA

Attachment #1 - CNPA and PBU Expansions and Contractions



Attachment #2 - Map of the CNPA



Attachment #3 - Proposed CNPA Tract Description, Allocation, and Ownership Schedule

ATTACHMENT 3
TRACTS WITHIN THE NIAKUK PA AND NIAKUK PA TRACT PARTICIPATIONS

Tract	Lease	Township /Range	Section	Acres	Royalty %	Working Interest Ownership % BPXA	ConocoPhillips	ExxonMobil	Chevron	Forest	Tract Participation
4	34625	12N-15E	Sec. 13: SW1/4SW1/4	40	12.5	26.355356	36.069385	36.395491	1.160000	0.019768	21.14%
			Sec. 14: S1/2, S1/2N1/2, S1/2N1/2N1/2	560							
			Sec. 23: All	640							
			Sec. 24: W1/2, W1/2SE1/4	400							
5	34626	12N-15E	Sec. 15: SE1/4	160	12.5	26.355356	36.069385	36.395491	1.160000	0.019768	16.81%
			Sec. 21: NE1/4, N1/2SE1/4	240							
			Sec. 22: All	640							
30	34629	12N-15E	Sec. 27: N1/2, N1/2S1/2	480	12.5	26.355356	36.069385	36.395491	1.160000	0.019768	8.31%
31	34630	12N-15E	Sec. 25: All	640	12.5	26.355356	36.069385	36.395491	1.160000	0.019768	18.95%
			Sec. 26: All	640							
			Sec. 36: NE1/4, N1/2NW1/4	240							
32	34635	12N-16E	Sec. 29: All	640	12.5	26.355356	36.069385	36.395491	1.160000	0.019768	31.53%
			Sec. 30: All	588							
			Sec. 31: N1/2	295.5							
			Sec. 32: N1/2	320							
33	34634	12N-16E	Sec. 28: N1/2, SW1/4 S1/2SE1/4, NW1/4SE1/4	600	12.5	26.355356	36.069385	36.395491	1.160000	0.019768	3.26%
			Sec. 33: N1/2N1/2	160							
Total				7283.5							100.00%

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

Attachment #4 - CNPA Data Submittal Requirement

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

1. Depth Structure Maps and **digital grids** (including faults) for each producing horizon.
2. Gross Isochore Maps and **digital grids** for each producing horizon
3. Hydrocarbon Net Pay Maps and **digital grids** for each producing horizon.
4. Average Porosity and Hydrocarbon Saturation Maps and **digital grids** for each producing horizon.
5. Hydrocarbon Pore Feet Maps and **digital grids** for each producing horizon.
6. Paper and **digital** copies of representative seismic lines to support the applied for action. Data submitted should include both strike and dip oriented lines, include picked horizons for all mapped surfaces, mapped faults, and wells demonstrating time-depth ties to well log formation picks. Lines should be clearly annotated with seismic survey ID, seismic volume, line number, picked horizon and well names. Map clearly showing location of all seismic and well sections provided.
7. Paper and **digital** copies of representative stratigraphic and structural well-log cross-sections. Cross-sections should include, log correlations for all mapped horizons, mapped faults, identified fluid contacts and deepest "oil down to" (ODT) and shallowest "water up to" (WUT) picks. Cross-sections should be of an appropriate scale that all annotations, picks, log curves and scales are clearly legible.
8. Hydrocarbon formation volume factors (B_o, B_g) applied to each reservoir.
9. Oil Gravity and/or Viscosity Maps and **digital grids** for each producing horizon.
10. **Digital file** (ascii or Excel spreadsheet) of formation picks in measured depth (MD) and sub-sea true vertical depth (sstvd) for each well, including all plug backs and pilot holes. Picks should include top and base of each producing interval, all known fluid contacts and deepest "oil down to" (ODT) and shallowest "water up to" (WUT) picks.
11. **Digital files** of calculated curve data from log analysis used in determining reservoir properties and in-place hydrocarbon volumes. Curve data should include total and/or effective porosity, water saturation, permeability, clay volume, and bulk volume water.
12. Criteria /cutoffs (i.e. porosity, saturation, volume shale, permeability...) used to determine net pay in each producing horizon.
13. **Digital file** (ascii or Excel spreadsheet) of calculated rock properties of each producing interval for every well. Data to include, top and base depth of interval in measured depth and sstvd, gross interval thickness (tvt), net sand thickness, net hydrocarbon pay thickness, net to gross ratio, average reservoir porosity, average reservoir water saturation (Sw), average permeability, permeability height (kh), and hydrocarbon pore feet
14. Location Map clearly showing all existing production, injection and planned wells in yearly POD. Horizontal wells should be shown as a line highlighting the existing and planned productive interval length. In addition, a **digital file** (ascii or Excel spreadsheet) provided with target x y coordinates for planned wells. For horizontal wells, x y coordinates for heel and toe locations should be provided for both existing and planned wells.
15. Summary of all oil and gas (including non-hydrocarbon constituents) compositional analyses, including gravity and viscosity data.
16. Paper and **digital** copies of all pressure build-up and fluid PVT analyses.
17. Relative permeability curves for oil/water, gas/oil, and gas/water.
18. Paper and **digital** copies of all capillary pressure analyses, where available.
19. Calculated original oil and/or gas in place (OOIP or OGIP) volumes
20. Estimated ultimate recoverable reserves (EUR) volume.
21. Proposed reservoir depletion plan.
22. Production forecast.

Computer applications have become the standard tool for evaluation, mapping and modeling of geologic data for the industry. Submittal of **digital data** is required to allow the State to apply the same level of tools to effectively query and evaluate the pertinent geological, geophysical, engineering, and well data, and interpretation of those data supplied by the operator.

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 support of the requested action in accordance with the applicable statutes and regulations in effect at the time of application.

Any data submitted to the state in connection with this application 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.

Attachment #5 – Objection to formation of CNPA

GIVENS LAW FIRM
P.O. Box 400, 912 E. Sherman Ave.
Coeur d'Alene, ID 83816-0400
phone (208) 676-1310
fax (208) 676-1296
raygivens@givenslaw.com
www.givenslaw.com

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DIVISION OF
OIL AND GAS

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 Consolidation of Niakuk P.A. and West Niakuk P.A. and Request for Other Action

Dear Mr. Van Dyke:

I write to you as the attorney of the Heirs of Andrew Oenga (Oenga Heirs) regarding BIA Allotment # F-14632. The purpose of this letter is to memorialize the Oenga Heirs' objection to the contemplated consolidation of the Niakuk P.A. and West Niakuk P.A., currently before the Alaska Department of Natural Resources (Department), and to suggest additional relief.

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. Oil and natural gas has been produced thru this Heald Point facility from the Niakuk P.A. for some time. Recently the Oenga Heirs learned that oil and gas from the West Niakuk P.A. was also being produced thru Heald Point. The Oenga Heirs have now learned that BPX is requesting the Department to consolidate the Niakuk P.A. and the West Niakuk P.A. into a single Participation Area. The difficulty is that the Lease does not authorize the use of the Heald Point property for the production of oil from any P.A. other than Niakuk.

A copy of the original Lease and the first letter amendment/notice regarding the Lease are attached and incorporated herein. They have recently been provided to the Alaska Oil and Gas Commission (Commission) regarding an objection to currently establish Raven Pool Rules. 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) (emphasis added), 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 our Niakuk oil accumulation.

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 participation area, such as West Niakuk. The Oenga Heirs raised this concern with BPX before Christmas (4 months ago). A Tolling Agreement, which expires the end of June, 2006, was entered into between BPX, the United States and the Oenga Heirs. The United States invited, thru BPX, the West Niakuk interest holders to participate in the Tolling Agreement. Unfortunately, a creditable and meaningful response has not been provided.

Consequently, the Oenga Heirs have been forced to send the attached Notice To Immediately Halt Trespass to BPX and each of the other West Niakuk participating companies. See attached Notice which is incorporated herein.

Because Lease # F-89-01 does not authorize production from the West Niakuk thru the Heald Point facility, the Oenga Heirs generally ask that the Department:

> 1) take any and all action within its jurisdiction to halt the production of oil and gas from West Niakuk P.A. thru Heald Point until this trespass matter is resolved, and
>
> 2) delay the consolidation of the Niakuk P.A. and West Niakuk P.A. until this matter is resolved.

Resolution of this matter could be established when all parties with an interest in Heald Point, its Lease, production facility and use of that facility, present the Department with their joint concurrence that oil and gas from West Niakuk can be produced thru Heald Point and the facility constructed thereon. The above action by the Department could provide a meaningful first step in preventing this matter from becoming embroiled in litigation and controversy for the foreseeable future.

An additional historical fact supports the above requests. In 1993, before West Niakuk oil began being produced thru the Heald Point facility, ARCO, predecessor in interest of ConocoPhillips as one of the State lease holders of the West Niakuk leases, approached the BIA requesting to lease a portion of the Oenga's Heald Point Allotment. See attached BIA telephone log. Unfortunately, this inquiry did not result in ARCO leasing a portion

of the Oengas' Heald Point property for a West Niakuk production facility. The Oenga Heirs' understanding is that BPX thereafter conveyed to ARCO two or three of its Heald Point directional wells for use in West Niakuk. This occurred at approximately the same time Exxon (the other West Niakuk leaseholder) removed its objection to the Commission establishing the Niakuk Pool Rules.

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 their property in the production of oil and gas from the Niakuk P.A. and nothing for the use of their property in the production of oil and gas from the West Niakuk P.A. This gross inequity should not be allowed to continue. Oil and gas from the West Niakuk P.A. should not be allowed to be produced thru the Heald Point facility contrary to the existing Lease.

The Oenga Heirs wish to make clear that they do not object to the eventual production of oil and gas from West Niakuk P.A. thru the Heald Point facility. Similarly they do not object to the eventual consolidation of the Niakuk P.A. and the West Niakuk P.A. These should occur, however, only after the Heald Point Lease is amended to appropriately reflect the additional use that is being made of the Oenga property and appropriate rental values for that use. Until then, it would be inappropriate to allow continued production of oil and gas from the West Niakuk P.A. thru Heald Point.

It could also be inappropriate to further complicate matters by consolidating Niakuk P.A. and West Niakuk P.A. when one is subject to a trespass claim and there is the potential for judicial action. All decisions made regarding this property will come under the scrutiny of the courts and the public in general unless the matter is now resolved.

Specifically, the Oenga Heirs request that the Department take the following action:

1) take any and all actions within its jurisdiction to halt the production of oil and gas from West Niakuk P.A. thru Heald Point until BPX, as lessee of BIA Lease #F-89-01, and the other West Niakuk interest holders can provide the Department with concurrence from all parties with an ownership interest in the Heald Point property that there exists the requisite legal authority to produce oil and gas from West Niakuk thru the Heald Point facility.

2) delay consolidation of the Niakuk P.A. and the West Niakuk P.A. until the above concurrence is provided.

The Department certainly has a legitimate interest in assuring itself that State leaseholders have a legally valid means of producing oil and gas from State leases. The relief requested would be in furtherance of that legitimate 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 West Niakuk 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 the Oenga Heirs

RCG:jr
Enclosure

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