STATE OF ALASKA
ALASKA OIL AND GAS CONSERVATION COMMISSION
333 West 7th Avenue, Suite 100
Anchorage, Alaska 99501

Re: **THE APPLICATION OF CONOCOPHILLIPS ALASKA, INC.** for an order to expand the affected area of AIO 2A for the Kuparuk River Oil Pool, Kuparuk River Unit, North Slope, Alaska	)	Area Injection Order No. 2B Kuparuk River Unit Kuparuk River Field Kuparuk River Oil Pool Ugnu Formation West Sak Oil Pool Tabasco Oil Pool December 12, 2002

IT APPEARING THAT:

1. By application dated September 4, 2002 ConocoPhillips Alaska, Inc., formerly known as Phillips Alaska, Inc., seeks to expand the affected area of Area Injection Order 2A, to accommodate Kuparuk River Oil Pool development at Drill Site 3S.

2. Notice of opportunity for public hearing was published in the Anchorage Daily News on September 27, 2002.

3. No comments concerning this application or requests for a public hearing were received.

4. 20 AAC 25.460 authorizes the Commission to issue an order permitting the underground injection of fluids on an area basis for wells within the same field, facility site, reservoir, project, or similar area.

5. Concurrently the Commission is issuing Conservation Order 432B expanding the affected area for Kuparuk River Oil Pool rules to accommodate development at Drill Site 3S.

FINDINGS:

1. **Operator** ConocoPhillips Alaska, Inc. ("CPA") is the operator of the Kuparuk River Oil Pool within the Kuparuk River Unit ("KRU").

2. **Proposed Development and Expansion** CPA requested authorization to inject fluids for the purpose of enhanced recovery operations in Umiat Meridian T12N-R7E Sections 1, 2, 11, 12, 13, 14, 15, 16, 21, 22, 23, and 24 in the KRU, North Slope, Alaska. A single new drill site, 3S ("DS 3S") with 20 wells, including 12 producers and 8 injectors is planned.

3. **Contraction of Affected Area of AIO 2A** The affected area of AIO 2A partially overlaps the affected area of AIO 10B for the Milne Point Unit. The following overlapping sections are contained within the Milne Point Unit:

   T12N, R11E Sections 5,6,7, and 8;

   T12N, R10E Sections 1,2,11, and 12;

   T13N, R9E Section 1, N ½ and SE ¼ Section 2, NE ¼ Section 11 and Section 12

4. **Strata Authorized for Enhanced Recovery** Area Injection Order 2, dated June 6, 1986 authorized injection for enhanced recovery in strata correlative to ARCO West Sak River State Well No. 1 between the measured depths of 3145 feet and 3640 feet (Ugnu Formation); 3744 feet and 4040 feet (West Sak Oil Pool); and 6474 feet and 6880 feet (Kuparuk River Oil Pool).

   Area Injection Order 2A, dated June 4, 1998 authorized injection for enhanced recovery in strata correlative to ARCO West Sak River State Well No. 1 between 4591 feet and 5324 feet (Tabasco Oil Pool).

   Enhanced recovery operations in the Kuparuk River Oil Pool within the Kuparuk River Unit are also governed by CO 432B and CO 198B.

5. **Aquifer Exemption** The Kuparuk River Oil pool is within the area covered by an aquifer exemption granted by the U.S. Environmental Protection Agency in 40 CFR 147.102(b)(3).

6. **Operators/Surface Owners** CPA provided all operators and surface owners within one-quarter mile of the proposed expansion area with a copy of the application for injection. Those operators are: ConocoPhillips Alaska, Inc., operator of Kuparuk River Unit. The State of Alaska, Department of Natural Resources is the only affected surface owner.

7. **Stratigraphy** The Kuparuk River Formation is a sequence of clastic sediments deposited on a shallow marine shelf during Neocomian (Early Cretaceous) time, about 140-120 million years ago. The formation is divided into Upper and Lower Members. These two Members are comprised of 4 Units, in ascending order, Units "A", "B", "C", and "D". The "A" and "C" units are the pay-bearing intervals in a major portion of the field.

   The Kuparuk River "C" Unit is composed of sandstones with subordinate conglomerates and lesser shales. "C" sediments were deposited in a variety of marginal marine environments. In general, conditions were marine to the east, within and beyond the KRU. In the west, evidence from secondary cements as well as trace fossils suggests a nearby source of fresh water and a shoreline. The Unit is divided into four intervals, "C1" through "C4". Intervals are successively younger upward, and axes of deposition shift successively southwest with time. Throughout the larger part of the KRU, "C" sand deposition and trends are controlled by syndepositional, northwest-trending normal faults.

Within the DS 3S area, the Palm #1 and #1A wells penetrated reservoir quality sands in the Hauterivian Kuparuk River "C4" interval at a depth of approximately 5750-5800 feet TVD. The Kuparuk River "A" Sand was found to be absent due to truncation by the Lower Cretaceous Unconformity (LCU) and the "C1" through "C3" intervals are absent because of non-deposition in the area.

The Kuparuk River "C4" sand reservoir is comprised of bioturbated, fine to medium-grained sandstone with variable amounts of glauconite, clay pellets, and siderite cement. It is separated from the underlying Miluveach mudstones by the regional Lower Cretaceous Unconformity ("LCU"). A transgressive surface of erosion marks the contact between "C4" sandstones and overlying mudstones of the Kalubik Formation. The "C4" interval in the area is interpreted to represent transgressive shoreface deposits on the flank of the Kuparuk trough. Accommodation and preservation of these shoreface deposits was created in part by deep-seated northwest-southeast trending normal faults.

The gross reservoir thickness logged in the Palm #1 and 1A wells ranges from 30 feet to 35 feet, with a corresponding net-to-gross ratio of approximately 0.73. A 15% porosity cutoff from wire line log derived porosity data Log model is used to count net pay. Average pay porosity ranges from 19% to 21%. Calculated log model water saturations for the Palm #1 and #1A wells are 12% and 13% respectively. Permeability ranges from less than 1 md to almost 1000 md. Fine scale (inches) changes in siderite composition and concentration play a dominant role in determining sandstone reservoir quality. Average permeability determined from well testing at Palm #1A is approximately 100 md.

Seismic mapping indicates that the gross thickness of the "C4" reservoir ranges from 7.5 feet to 35 feet in the DS 3S area.

8. **Structure Overview** The eastern portion of the DS 3S area contains a high density of North-South trending normal faults. The western portion of the area is moderately faulted and dips gently to the Northwest.

9. **Well Logs** The logs of existing injection wells are on file with the Commission.

10. **Confining Intervals** The Kuparuk River "C4" Sands in the DS 3S area are overlain by approximately 600 feet of confining shales, which act as an impermeable barrier. These confining shale zones, comprised of approximately 180 feet of Kalubik Shale, 170 feet of HRZ and 250 feet of Torok Shale, are the same shales that overly the main Kuparuk River Field Oil Pool and have demonstrated over time that fractures do not propagate through the confining zones. The lower confining interval consists of the Miluveach and Kingak shales, which exceed 1,500 feet in combined thickness.

11. **Hydrocarbon Recovery** The Kuparuk River Formation is estimated to contain 74 million barrels original oil in place (OOIP) in the area based on exploratory drilling and seismic mapping. An enhanced recovery process is planned within six months of production start-up. Studies conducted by CPA resulted in selecting the alternating cycling of water and miscible gas ("MWAG") process. The MWAG process yielded

greater recoveries than other processes evaluated which included primary, waterflood, miscible injection and lean gas flood. Recovery is expected to be 36 million barrels oil or about 48% of the OOIP including primary, waterflood and enhanced recovery. Estimated recoveries from simulation studies of the DS 3S area are primary – 20%, waterflood – 20% and MWAG – 6-8%. As a comparison, ongoing MWAG processes in the main Kuparuk reservoir "C" sands to the east have experienced incremental oil recovery of 8%-12% OOIP over base waterflood recoveries.

The final phase lean gas injection is expected to maximize recovery of the light hydrocarbon liquids that were injected into the reservoir as part of the MWAG stream. The source of the lean gas will likely be KRU's Central Production Facility-2 ("CPF-2"). However, other potential gas sources will be considered.

12. **Type of Injection Fluid/Source** CPA is requesting authorization to inject alternating cycles of water and miscible gas ("MWAG"). Miscible injectant ("MI") is available within the KRU and by nominal pipeline extension to DS 3S. Application of MWAG at DS 3S will be optimized within the available sites currently taking MI and those awaiting injection. A new 8-inch water injection line runs from Drill Site 3G to 3S and an 8-inch MI injection line runs from KRU Drill Site 3F past Drill Site 3G to DS 3S.

    The MI will be the same as that used in the KRU Large Scale EOR Project. MI is manufactured at KRU Central Production Facility-1 ("CPF-1") and CPF-2 by blending lean gas from the production facilities with light liquid hydrocarbon solvent from the Prudhoe Bay Unit ("PBU") (source is Natural Gas Liquids from the Central Gathering Facilities) and KRU scrubber liquids from gas lift compression systems (CPF-1 and 2), NGLs (CPF-1) and naphtha (KRU Topping Plant).

    Produced water from KRU production facilities will be used for pressure maintenance and MWAG enhanced recovery.

13. **Fluid Composition and Compatibility with Formation** Laboratory experiments and compositional studies conducted by CPA indicate no evidence of compatibility problems between the fluids planned for injection and the Kuparuk River "C4" reservoir or its confining layers.

14. **Injection Rates and Pressures** The maximum water injection rate is estimated at 24,000 barrels of water per day in the DS 3S project area. Maximum MI and lean gas injection rate is expected to be 22 million standard cubic feet per day.

    The expected maximum surface injection pressure for water is 2800 psi and for MI it is 3600 psi.

15. **Mechanical Integrity and Well Design** CPA will construct two types of wells to develop the DS 3S area. Injectors and producers will be constructed with either long string or top set completions. A long string completion will employ 30" conductor casing to approximately 75 feet, 9-5/8" surface casing set below the base of the West Sak Formation, 7" production casing run from surface through the Kuparuk River Formation. Top set completions will employ 30" conductor casing to approximately 75 feet, 9-5/8" surface casing set below the base of the West Sak Formation, with 7"

intermediate casing run from surface to just above the Kuparuk River Formation with a 3-1/2" production liner set through the production interval.

DS 3S injection wells will be designed to comply with the requirements specified in 20 AAC 25.412. All injection wells will have the casing pressure tested in accordance with 20 AAC 25.030. A state witnessed MIT is required on wells prior to injection startup. Injection well tubing/casing annulus pressures will be monitored and recorded on a regular basis.

16. **Mechanical Condition of Wells Within One-Quarter Mile** There are no current active wells within the DS 3S expansion area. The Colville #1 and Kalubik Creek #1 wells have been plugged and abandoned according to 20 AAC 25.112. Production and injection wells will be designed in compliance with 20 AAC 25.

CONCLUSIONS:

1. The application requirements of 20 AAC 25.402 have been met.
2. Expanding the area covered by AIO 2A is appropriate for the proposed development project in the DS 3S area. Expansion under this order will prevent waste, protect fresh water, protect correlative rights, and ensure greater ultimate recovery.
3. It is appropriate to contract the sections governed by the Milne Point Unit AIO 10B from the affected area of this order.
4. Information provided in this application and within the concurrent application for pool rules area expansion shows that water injection and MWAG will significantly improve recovery.
5. Injected fluids will be confined within the appropriate receiving intervals by impermeable lithology, cement isolation of the wellbore and appropriate operating conditions.
6. The Kuparuk River Oil Pool injection wells are designed to comply with the mechanical integrity requirements specified in 20 AAC 25.412.
7. Reservoir surveillance required by this order, CO 432B, 198B, operating parameter surveillance and mechanical integrity tests will demonstrate performance of the enhanced oil recovery project, disclose possible abnormalities and indicate integrity problems.

NOW, THEREFORE, IT IS ORDERED:

1. This AIO supersedes AIO 2A, dated June 4, 1998. The findings, conclusions and administrative record for AIO 2A are adopted by reference and incorporated in this decision.

2. The affected area of this AIO is expanded to include T12N, R7E Sections 1, 2, 11, 12, 13, 14, 15, 16, 21, 22, 23 and 24; and contracted to exclude T12N, R11E Sections 5,6,7, and 8; T12N, R10E Sections 1,2,11, and 12.

3. The affected area for CO 198B is expanded to include T12N, R7E Sections 1, 2, 11, 12, 13, 14, 15, 16, 21, 22, 23 and 24.

4. In addition to the statewide requirements under 20 AAC 25 (to the extent not superseded by these rules or other conservation orders), the following rules govern Class II injection operations in the following affected area:

Umiat Meridian

Township-Range	Sections
T13N, R8E	1, 2, 3,10, 11, 12, 13, 14, 15, 23, 24, 25, 26, 27, 33, 34, 35, 36.
T13N, R9E	SW ¼ Section 2, 3, 4, 5, 6, 7, 8, 9, 10, S ½ & NW ¼ Section 11, 15, 16, 17, 18, 19, 20, 21, 22, 25, 26, 27, 28, 29, 30, 31, 32, 33, 34, 35, 36.
T12N, R7E	1, 2, 11, 12, 13, 14, 15, 16, 21, 22, 23, and 24.
T12N, R8E	Entire Township
T12N, R9E	Entire Township
T12N, R10E	3, 4, 5, 6, 7, 8, 9, 10, 14, 15, 16, 17, 18, 19, 20, 21, 22, 23, 25, 26, 27, 28, 29, 30, 31, 32, 33, 34, 35, 36.
T12N, R11E	31
T11N, R7E	24, 25, 26, 34, 35, 36.
T11N, R8E	Entire Township
T11N, R9E	Entire Township
T11N, R10E	Entire Township
T11N, R11E	5, 6, 7, 8, 16, 17, 18, 19, 20, 21, 22, 27, 28, 29, 30, 31, 32, 33.
T10N, R7E	1, 2, 3, 4, 9, 10, 11, 12, 13, 14, 15, 16, 21, 22, 23, 24, 25, 26, 27, 28, 33, 34, 35, 36.
T10N, R8E	Entire Township
T10N, R9E	Entire Township.
T10N, R10E	Entire Township.

T10N, R11E	5, 6, 7, 8, 17, 18, 19, 20, 29, 30, 31, 32.
T9N, R9E	3, 4, 5, 6, 7, 8, 9, 10, 13, 14, 15, 16, 17, 18, 19, 20, 21, 22, 23, 24.
T9N, R10E	1, 2, 3, 4, 9, 10, 11, 12, 13, 14, 15, 16, 21, 22, 23, 24, 27, 28, 33, 34.
T9N, R11E	5, 6, 7, 8, 17, 18, 19, 20.

Rule 1. Authorized Injection Strata for Enhanced Recovery

Within the affected area, non-hazardous fluids may be injected for purposes of pressure maintenance and enhanced oil recovery into strata defined as those strata which correlate with the strata found in the ARCO West Sak River State Well No. 1 between the measured depths of 3145 feet and 3640 feet; 3744 feet and 4040 feet; 4591 feet and 5324 feet; and 6474 feet and 6880 feet.

Rule 2. Authorized Injection Strata for Disposal

Within the affected area, Class II oil field fluids may be injected in conformance with 20 AAC 25 for the purpose of fluid disposal into strata defined as those strata which correlate with the strata found in ARCO West Sak River State Well No. 1 between the measured depths of 3390 feet and 3640 feet; and with the strata found in ARCO/BP Ugnu Well No. 1 between the measured depths of 8370 feet and 8800 feet; within tract ADL 25648 (Sections 3, 4, 9, and 10, T11N, R10E, UM) into the zone which correlates with the strata found in ARCO West Sak River State Well No. 1 between the measured depths of 3145 feet and 3390 feet; and within portions of tracts ADL 355023, ADL 355024, and ADL 373301 (Sections 3, 4, 5, 8, 9 and 10, T13N, R9E) into the non-hydrocarbon bearing portions of the zone which correlates with the strata found in ARCO Oliktok Point Well No. 2 between the measured depths of 2937 feet and 3544 feet.

Rule 3. Fluid Injection Wells

The underground injection of fluids must be: 1) through a new well that has been permitted for drilling as a service well for injection in conformance with 20 AAC 25.005; 2) through an existing well that has been approved for conversion to a service well for injection in conformance with 20 AAC 25.280; or 3) through a well that existed as a service well for injection purposes on the date of this order. The pumping away of drilling mud, rock cuttings and other-waste as provided for in 20 AAC 25.080 into an exploratory or stratigraphic test well, or into the annuli of any well approved in accordance with 20 AAC 25.005, is an operation incidental to the drilling of the well, and is not considered a disposal operation subject to regulation as an injection well (Class II or otherwise) under authority of the UIC program.

Rule 4. Monitoring the Tubing/Casing Annulus Pressures

The tubing/casing annulus pressure of each injection well must be checked weekly, as a routine duty, to ensure there is no leakage and that it does not exceed a pressure that will subject the casing to a hoop stress greater than 70% of the casing's minimum yield strength.

Rule 5. Reporting of Tubing/Casing Annulus Pressure Variations

Tubing/casing annulus pressure variations between consecutive observations need not be reported to the Commission.

Rule 6. Demonstration of Tubing/Casing Annulus Mechanical Integrity

A schedule must be developed and coordinated with the Commission, which ensures that the tubing/casing annulus for each injection well is pressure tested prior to initiating injection and at least once every four years thereafter. A test surface pressure of 1500 psi or 0.25 psi/ft multiplied by the vertical depth of the packer, whichever is greater, but not to exceed a hoop stress greater than 70% of the casing's minimum yield strength, must be held for 30 minutes with no more than a 10 percent decline. Alternative EPA methods may also be used with Commission approval, including but not limited to timed-run radioactive tracer survey (RTS), oxygen activation logs, temperature logs and noise logs. Wells with tubing-to-casing communication must be surveyed or logged every other year and wells which demonstrate mechanical integrity every fourth year. The Commission must be notified at least 24 hours in advance to enable a representative to witness pressure tests or the application of alternative methods.

Rule 7. Well Integrity Failure

Whenever operating pressure observances or pressure tests indicate pressure communication or leakage of any casing, tubing or packer, the operator must notify the Commission on the first working day following the observation, obtain Commission approval of a plan for corrective action, and when an USDW is not endangered, obtain Commission approval to continue injection.

Rule 8. Plugging and Abandonment of Fluid Injection Wells

An injection well located within the affected area must not be plugged or abandoned unless approved by the Commission in accordance with 20 AAC 25.105.

Rule 9. Administrative Relief

Upon request, the Commission may administratively amend any rule stated above as long as the operator demonstrates to the Commission's satisfaction that sound engineering practices are maintained and the amendment will not result in an increased risk of fluid movement into an underground source of drinking water.

DONE at Anchorage, Alaska and dated December 12, 2002.

Cammy Oechsli Taylor, Chair
Alaska Oil and Gas Conservation Commission

Daniel T. Seamount, Jr., Commissioner
Alaska Oil and Gas Conservation Commission

Michael L. Bill, P.E., Commissioner
Alaska Oil and Gas Conservation Commission

AS 31.05.080 provides that within 20 days after receipt of written notice of the entry of an order, a person affected by it Month file with the Commission an application for rehearing. A request for rehearing must be received by 4:30 PM on the 23rd day following the date of the order, or next working day if a holiday or weekend, to be timely filed. The Commission shall grant or refuse the application in whole or in part within 10 days. The Commission can refuse an application by not acting on it within the 10-day period. An affected person has 30 days from the date the Commission refuses the application or mails (or otherwise distributes) an order upon rehearing, both being the final order of the Commission, to appeal the decision to Superior Court. Where a request for rehearing is denied by non-action of the Commission, the 30-day period for appeal to Superior Court runs from the date on which the request is deemed denied (i.e., 10th day after the application for rehearing was filed).