STATE OF ALASKA
OIL AND GAS CONSERVATION COMMISSION
3001 Porcupine Drive
Anchorage, Alaska 99501-3192

Re:	**The APPLICATION OF PHILLIPS ALASKA, Inc.** ("PHILLIPS") for an order allowing injection of fluids for enhanced oil recovery in the Midnight Sun Oil Pool, Midnight Sun Participating Area, Prudhoe BayField.	)	**Area Injection Order No. 20** Prudhoe Bay Field Midnight Sun Participating Area Midnight Sun Oil Pool
			September 28, 2000

IT APPEARING THAT:

1. By letter dated February 17, 2000, and application dated May 3, 2000, Phillips Alaska, Inc. ("PHILLIPS") requested authorization from the Alaska Oil and Gas Conservation Commission ("Commission") to allow injection of fluids for enhanced oil recovery into the Midnight Sun Oil Pool. PHILLIPS provided supplemental information on June 12, 2000.
2. Notice of Public Hearing was published in the Anchorage Daily News on February 25, 2000, and a hearing was scheduled for April 4, 2000. On March 27, 2000, PHILLIPS requested the hearing be rescheduled. On April 1, 2000, a Notice of Cancellation of Public Hearing was published in the Anchorage Daily News. A second Notice of Public Hearing was published in the Anchorage Daily News on May 10, 2000, and the hearing was rescheduled to June 13, 2000.
3. A hearing concerning the applicant's request was convened in conformance with 20 AAC 25.540 at the Commission's offices, 3001 Porcupine Drive, Anchorage, Alaska 99501 on June 13, 2000. Concurrently, the Commission heard testimony to establish pool rules for the Midnight Sun Oil Pool.

FINDINGS:

1. Commission regulation 20 AAC 25.460 provides authority to issue an order governing underground injection of fluids on an area basis for all wells within the same field, facility site, reservoir, project, or similar area.
2. PHILLIPS presented testimony in support of an application for pool rules and area injection order for the proposed Midnight Sun Oil Pool ("MSOP") on June 13, 2000.
3. The Midnight Sun Participating Area is located within the Prudhoe Bay Unit (PBU) on Alaska's North Slope.
4. The Commission approved the designation of BP Exploration (Alaska) Inc. ("BPXA") as sole operator of the PBU effective July 1, 2000.
5. BPXA is the designated operator of all wells within one-quarter mile of the area proposed for enhanced oil recovery. The State of Alaska is the surface owner.
6. The U.S. Environmental Protection Agency has exempted all aquifers in the Western Operating Area of the Prudhoe Bay Field, including the area containing the MSOP by letter dated July 1, 1986. The EPA action was considered a minor exemption and a non-substantial program revision and did not require notice in the Federal Register (Aquifer Exemption Order No. 1, July 11, 1986.

7. The MSOP is contained within the Lower Cretaceous-aged Kuparuk Formation and correlates with the interval between the measured depths of 11,662 and 11,805 feet in the PBU E-100 well. The interval lies approximately 8,000 feet below sea level with a typical gross sand thickness of about 110 feet.
8. Within the MSOP, the Kuparuk Formation can be informally divided into upper and lower lithologic units. The upper unit ranges from 0 to 70 feet in thickness, and consists of interbedded sandstone that contains varying amounts of glauconite, siderite and minor amounts of muddy siltstone. The lower unit is about 40 feet thick. The lower unit is generally composed of very fine to fine grained, quartz-rich, porous sandstone.
9. Mean porosity in the upper Kuparuk unit is 20.7% and mean permeability is 200 millidarcies. Mean porosity and permeability in the reservoir interval of the lower Kuparuk unit are 27.3% and 760 millidarcies, respectively. Mean water saturation is 26.4% for the upper Kuparuk Formation and 12.6% for the reservoir interval of the lower Kuparuk unit.
10. The Kuparuk Formation is confined above by approximately 110 feet of shale assigned to the Kalubik and High Radioactive (HRZ) Zones. Log derived mechanical properties for the Kalubik / HRZ indicate a fracture gradient of 0.8 to 0.9 psi/ft.
11. Approximately 950 feet of shale in the Miluveach and Kingak Formations confines the Kuparuk Formation below. A single leakoff test in the Kingak shale yielded a leakoff gradient of approximately 0.85 psi/ft.
12. No tests have been conducted at MSOP to determine breakdown pressure for the Kuparuk Formation. Fracture gradient data from offset fields ranges between 0.6 and 0.7 psi/ft at initial reservoir conditions.
13. MSOP crude oil gravity is approximately 25.5 degrees API, solution gas-oil-ratio is 717 scf/stb, formation volume factor is 1.33 reservoir barrels per stock tank barrel, and oil viscosity is 1.68 centipoise at the bubble point pressure, 4045 psia. Initial reservoir pressure is 4058 psia and temperature is 160 degrees Fahrenheit at the reservoir datum of 8050 true vertical depth sub sea.
14. Steady state water-oil relative permeability data indicate 23% residual oil saturation on a core flood test. Limited results from centrifuge water-oil and gas-oil experiments indicate water-oil relative permeability for MSOP should be similar to that measured for other North Slope fields. Analog data were used in predictive model reservoir performance studies.
15. Gas coning and gas under-running may impact reservoir performance as the gas cap overlies slightly more than 50% of the oil column.
16. Simulation results indicate recovery will be maximized if voidage is balanced by injecting water into the PBU E-100 well in the mid-field area of the MSOP once reservoir pressure has been restored to the 3800 to 4000 psi range.
17. Well PBU E-100 will be converted to injection service at a rate of 20,000-25,000 barrels of water per day.
18. MSOP oil production is expected to peak at a rate of 8,000 to 10,000 barrels per day prior to waterflood breakthrough.
19. Injection water will come from two source water wells drilled at PBU E-Pad and completed in the Tertiary-age, Sagavanirktok Formation. Produced water from Gathering Center #1 (GC-1) or produced water separated directly from Midnight Sun production at E-Pad will be considered as potential alternative sources of injection water.
20. Produced water samples analyzed from nearby well DS #15-06 and GC-1 provided 47,005 mg/l and 19,985 mg/l total dissolved solids, respectively.

21. Geochemical model results indicate that a combined Tertiary water and connate water is likely to form calcium carbonate and barium sulfate scale. Similar scale precipitation is anticipated for produced water. Scale will be controlled with commonly available inhibitors.
22. Expected average wellhead injection pressure is 2250 psig, maximum wellhead injection pressure is 2750 psig, and maximum bottom hole pressure is 6000 psig.
23. PHILLIPS stated maximum injection pressure is not likely to initiate or propagate fractures through confining strata based on fracture propagation models, mechanical property logs and analog information from other Kuparuk formation developments.
24. Well PBU E-100 is completed with 9 5/8" 47 #/ft casing to 4,441' measured depth (MD), 7" 29 #/ft casing set at 12,906'MD, and 4 ½" 12.6 #/ft tubing set to 11,646' MD, with a 7" packer at 11,620' MD. Open perforations are from 11,775' to 11,790' MD.
25. A cement bond log run on well PBU E-100 indicates top of cement lies at 10,650' MD, with adequate cementation above the perforations. A copy of the log is on file with the Commission.
26. BPXA will demonstrate the mechanical integrity of well PBU E-100 as specified in 20 AAC 25.412 prior to initiating injection operations.
27. The operator will comply with the requirements of 20 AAC 25.402 (d) and (e) to monitor tubing-casing annulus pressures of injection wells periodically during injection operations to ensure there is no leakage and that casing pressure remains less than 70% of minimum yield strength of the casing.
28. All existing wells drilled within the proposed project area have been constructed in accordance with 20 AAC 25.030. All wells abandoned in the proposed project area have been abandoned in accordance with 20 AAC 25.105 and 20 AAC 25.112, or an equivalent precursor regulation.
29. PHILLIPS envisions a three-well field, including the drilling of one additional upstructure producing well. Additional injection and production wells may be considered depending on reservoir performance and ongoing technical evaluation.
30. The estimated original oil in place ("OOIP") in the MSOP ranges from 40 to 60 MMBO. Total gas in place is estimated between 100 to 130 bscf. Free gas volume associated with the gas cap is estimated between 60 and 80 bscf.
31. Recovery estimated from reservoir simulation of primary depletion is approximately 14% of the OOIP, about 6 to 8 MMBO. Estimates of incremental waterflood recovery ranges from 15 to 25% of the OOIP, or 10 to 15 MMBO, with 0.7 pore volumes of water injected.

CONCLUSIONS:

1. The application requirements of 20 AAC 25.402 have been met.
2. An Area Injection Order is appropriate for the project area in accordance with 20 AAC 25.460.
3. The U.S. Environmental Protection Agency has exempted all aquifers in the Western Operating and K-Pad Areas of the Prudhoe Bay Field, including the proposed MSOP by letter dated July 1, 1986 (Aquifer Exemption Order No. 1, July 11, 1986).
4. The proposed injection operations will be conducted in permeable strata, which can reasonably be expected to accept injected fluids at pressures less than the fracture pressure of the confining strata.
5. Injected fluids will be confined within the appropriate receiving intervals by impermeable lithology, cement isolation of the wellbore and appropriate operating conditions.
6. Injection water limited to that produced is the most beneficial and efficient approach to enhanced recovery at this time.

7. The proposed MSOP water injection project will result in 15 to 25 percent (about 10 to 15 million barrels) increased recovery over primary production alone.
8. Reservoir surveillance, operating parameter surveillance and mechanical integrity tests will demonstrate appropriate performance of the enhanced oil recovery project or disclose possible abnormalities.
9. An Area Injection Order enabling enhanced oil recovery activity will not cause waste nor jeopardize correlative rights.

NOW, THEREFORE, IT IS ORDERED that the following rules, in addition to statewide requirements under 20 AAC 25, govern Class II enhanced oil recovery injection operations in the affected area described below:

UMIAT MERIDIAN

T12N R13E Section 25, S ½; Section 36, N ½, SE ¼, E ½ of SW 1/4
T12N R14E Section 29, all; Section 30, S ½, S ½ of NE ¼, S ½ of NW ¼; Section 31, N ½, SW ¼, N ½ of SE ¼; Section 32, NW ¼; Section 28, W ½, W ½ of NE ¼, W ½ of SE ¼

Rule 1 Authorized Injection Strata for Enhanced Recovery

Within the affected area, fluids appropriate for enhanced recovery may be injected for purposes of pressure maintenance and enhanced recovery into strata that are common to, and correlate with, the interval between the measured depths of 11,662 and 11,805 feet in the PBU E-100 well.

Rule 2 Fluid Injection Wells

The underground injection of fluids must be through a well permitted for drilling as a service well for injection in conformance with 20 AAC 25.005, or through a well approved for conversion to a service well for injection in conformance with 20 AAC 25.280.

Rule 3 Monitoring the Tubing-Casing Annulus Pressure Variations

The tubing-casing annulus pressure and injection rate of each injection well must be checked at least weekly 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 4 Reporting the Tubing-Casing Annulus Pressure Variations

Tubing-casing annulus pressure variations between consecutive observations need not be reported to the Commission unless well integrity failure is indicated as in Rule 6 below.

Rule 5 Demonstration of Tubing-Casing Annulus Mechanical Integrity

A schedule must be developed and coordinated with the Commission that ensures that the tubing-casing annulus for each injection well is pressure tested prior to initiating injection, following well workovers affecting mechanical integrity, 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, will be used. The test pressure must show a stabilizing trend and must not decline more than 10% in a thirty-minute period. The Commission must be notified at least twenty-four (24) hours in advance to enable a representative to witness pressure tests.

Rule 6 Well Integrity Failure

Whenever operating pressure observations, injection rates, 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 to continue injection and submit a plan of corrective action on Form 10-403 for Commission approval.

Rule 7 Plugging and Abandonment of 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 8 Notification

The operator must notify the Commission if it learns of any improper Class II injection. Additionally, notification requirements of any other State or Federal agency remain the operators' responsibility.

Rule 9 Administrative Action

Upon proper application, the Commission may administratively waive the requirements of any rule stated above or administratively amend any rule as long as the change does not promote waste or jeopardize correlative rights, is based on sound engineering and geoscience principles and will not result in an increased risk of fluid movement into a USDW.

DONE at Anchorage, Alaska and dated September 28, 2000

Camillé Oechsli Taylor, Commissioner
Alaska Oil and Gas Conservation Commission

Daniel T. Seamount Jr., 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 may 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 nonaction 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).