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

Re: **The APPLICATION OF BP Exploration (Alaska) Inc.** ("BPXA") for an order allowing injection of fluids for enhanced oil recovery into the Eider Oil Pool in the Endicott Field.	))))))	**Area Injection Order No. 19** Duck Island Unit Endicott Field Eider Oil Pool June 2, 2000

IT APPEARING THAT:

1. By application dated January 27, 2000, BP Exploration (Alaska) Inc. ("BPXA") requested authorization from the Alaska Oil and Gas Conservation Commission ("Commission") to allow injection of fluids for enhanced oil recovery into the Eider Pool. Supplemental information was also provided by letters dated February 4, 2000, February 17, 2000, and May 30, 2000.

2. Notice of opportunity for public hearing was published in the Anchorage Daily News on February 5, 2000. A second public hearing notice changing the date of public hearing was published in the Anchorage Daily News on March 3, 2000. A third public hearing notice for a continuance of the hearing was published in the Anchorage Daily News on April 15, 2000.

3. The Commission did not receive any protests or requests for a public hearing.

4. BPXA personnel met with Commission staff on April 13, 2000 and presented testimony at hearings held at the Commission's offices on April 6, 2000 and May 25, 2000.

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. BPXA presented testimony in support of an application for pool rules and area injection order for the proposed Eider Oil Pool ("EOP") on April 6, 2000 and May 25, 2000. Definition of this pool is pending.

3. The Duck Island Unit has been expanded and the Prudhoe Bay Unit has been contracted to accommodate development of the proposed EOP.

4. The proposed EOP is not common to any pool currently approved for enhanced recovery, however the affected area is located in the northeastern portion of the Area Injection Order No. 4C (Eastern Operating Area of Prudhoe Bay Unit) and in the western portion of the Area injection Order No. 1 (Duck Island Unit).

5. BPXA is the sole 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 proposed EOP is defined as the accumulation of hydrocarbons that are common to and which correlate with the accumulation in the BP Exploration 2-56A/EI01 well between the measured depths of 16785 and 17928 feet and consists of the Sag River, Shublik and Ivishak Formations.

7. Within the proposed EOP producible oil is known to exist within the Ivishak Formation which occurs in the BP Exploration 2-56A/EI01 well between the measured depths of 17338 and 17928 feet.

8. Water injection for enhanced oil recovery will be limited to the proposed EOP Ivishak Formation.

9. The proposed EOP Ivishak Formation is composed of three stratigraphic units named, in stratigraphic order, the Lower Sand, Middle Shale, and Upper Sand.

10. The Lower Sand has a gross thickness ranging from 80 to 125 feet, a net to gross ratio of .8, an average porosity of 21% and an average permeability of 30 millidarcies.

11. The Middle Shale has a gross thickness ranging from 75 to 90 feet, a net to gross ratio of .5, an average porosity of 16% and an average permeability of 300 millidarcies.

12. The Upper Sand has a gross thickness ranging from 60 to 125 feet, a net to gross ratio of .8, an average porosity of 20% and an average permeability of 300 millidaries.

13. The three stratigraphic units constitute a single flow unit due to vertical permeability enhancement by faulting and fracturing.

14. The proposed EOP is confined below by more than fifty feet of the Kavik Shale.

15. Several hundred feet of shales within the Shublik and HRZ Formations overly the proposed EOP Ivishak Formation.

16. BPXA has drilled a total of two completed wells, the 2-56A/EI01, the 2-30A/EI02, and five additional sidetracks or plugbacks into the Eider accumulation.

17. Reservoir surveillance data combined with a full field reservoir simulation indicate converting well 2-56A/EI01 to water injection service and maintaining voidage replacement will maximize recovery from the proposed EOP.

18. BPXA does not intend to repressurize the reservoir to its original pressure because there is potential risk of lost reserves from resaturating the gas cap.

19. Recovery from primary depletion is estimated at 15% OOIP, while recovery with water injection is estimated at 27-38%, an incremental recovery of 12-23%.

20. BPXA plans to inject seawater and/or produced water from EOP or Endicott facilities consisting of Sag Delta North and Endicott pools. A formation water analysis will be conducted prior to initiating injection operations to ensure compatibility of the injected water with formation water.

21. Maximum expected injection rate is 17,000 barrels of water per day.

22. Estimated average wellhead injection pressure is 2200 psia, maximum wellhead injection pressure is estimated at 2700 psia.

23. Salinity estimates from wireline logs submitted for the original Duck Island Unit area injection order application ranged from 18,000 to 32,000 milligrams per liter ("mg/L") total dissolved solids ("TDS") throughout the sub-permafrost stratigraphic section in the Duck Island Unit Area.

24. Salinity estimates from wireline logs submitted for the Eastern Operating Area of the Prudhoe Bay Unit area injection order application ranged from 13,000 to 55,000 milligrams per liter ("mg/L") total dissolved solids ("TDS") throughout the sub-permafrost stratigraphic section.

25. Well 2-56A/EI01 is completed with 9 5/8" 47 #/ft casing to 7,079' measured depth (MD), 7" 29 #/ft liner set at 15,958'MD, a 4 ½" 12.6 #/ft liner to 17,988', 4 ½" 12.6 #/ft tubing set to 15,176' MD with a 7" packer at 15,199' MD. Open perforations are from 17,714' to 17,904' MD.

26. A cement bond log run on well 2-56A/EI01 indicates top of cement at 16,300'. A copy of the log is on file with the Commission.

27. BPXA will demonstrate the mechanical integrity of well 2-56A/EI01 as specified in 20 AAC 25.412 prior to initiating injection operations.

28. The operator will comply with the requirements of 20 AAC 25.402 (d) & (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.

29. 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.

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. No underground sources of drinking water ("USDW's") exist beneath the permafrost in the area of the Eider oil accumulation.

4. The proposed injection operations will be conducted in permeable strata, which reasonably can be expected to accept injected fluids at pressures less than the fracture pressure of the confining strata.

5. Injection fluids limited to produced fluid and/or seawater are the most beneficial and efficient approach to enhanced recovery at this time.

6. Injected fluids will be confined within the appropriate receiving intervals by impermeable lithology, cement isolation of the wellbore and appropriate operating conditions.

7. The EOP enhanced oil recovery project will result in significant additional hydrocarbon recovery from the pool.

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 order enabling enhanced oil recovery activity will not cause waste nor jeopardize correlative rights.

NOW, THEREFORE, IT IS ORDERED that the following rules govern Class II enhanced oil recovery injection operations in the affected area described below:

UMIAT MERIDIAN

T12N R16E Section 27: all
Section 28: NE ¼ 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 17338 and 17928 feet in the BP Exploration 2-56A/EI01 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 principles and will not result in an increased risk of fluid movement into a USDW.

DONE at Anchorage, Alaska and dated June 2, 2000.

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Camillé Oechsli Taylor, Commissioner
Alaska Oil and Gas Conservation Commission

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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).