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

Re:	**THE APPLICATION OF BP EXPLORATION (ALASKA) INC.** for an order allowing underground injection of fluids for enhanced oil recovery in Aurora Oil Pool, Prudhoe Bay Field, North Slope, Alaska	Prudhoe Bay Field Aurora Oil Pool Area Injection Order No. 22B May 6, 2003

IT APPEARING THAT:

1. By letter and application dated December 9, 2002, BP Exploration (Alaska) Inc. ("BPXA") requested an order from the Alaska Oil and Gas Conservation Commission ("Commission") modifying Area Injection Order No. 22 ("AIO 22") authorizing underground injection of miscible injectant ("MI") for enhanced oil recovery in the Aurora Oil Pool ("AOP"), Prudhoe Bay Field, on the North Slope of Alaska.
2. Notice of opportunity for public hearing was published in the Anchorage Daily News on January 28, 2003.
3. The Commission did not receive any protests or comments concerning this application.
4. A hearing concerning BPXA's request was convened in conformance with 20 AAC 25.540 at the Commission's offices, 333 W. 7th Avenue, Suite 100, Anchorage, Alaska 99501 on March 4, 2003.
5. BPXA provided additional information on February 28, 2003 and on March 7, 2003.
6. On April 3, 2003 the Commission issued Area Injection Order No. 22A ("AIO 22A") denying BPXA's application to inject enriched gas in the AOP.
7. On April 28, 2003 BPXA applied for rehearing of AIO 22A and supplied additional information in support of their application.

FINDINGS:

1. Operators/Surface Owners (20 AAC 25.402(c)(2) and 20 AAC 25.403(c)(3))

   BP Exploration (Alaska) Inc., ExxonMobil Alaska Production Inc., ConocoPhillips Alaska, Inc., Chevron U.S.A. Production, and Forest Oil Corporation are working interest owners. The State of Alaska is the landowner.

2. Project Area Requested for Enhanced Recovery

   The AOP is defined as an accumulation of oil that is common to, and correlates with, the interval between 6765'- 7765' measured depth ("MD") in the Mobil Oil Corporation Mobil-Phillips North Kuparuk State No. 26-12-12 well. The geology of the AOP is described in Conservation Order 457 ("CO 457") and AIO 22.

3. Description of Operation (20 AAC 25.402(c)(4))

   The AOP is developed from the Prudhoe Bay S-Pad. Tract operations within the pool began in November 2000. The Commission approved water injection with the issuance of AIO 22 on September 7, 2001.

   The proposed project involves the cyclical injection of water alternating with enriched hydrocarbon gas into the oil column of the Kuparuk River Formation of the AOP. The injectant will be comprised of hydrocarbon gas, enriched with intermediate hydrocarbons, principally ethane and propane, which is designed to be miscible with the reservoir oil. The proposed source of this enriched gas is from pools within the Prudhoe Bay Unit and processed within the Prudhoe Bay Central Gas Facility.

   Requested timing for injection of enriched gas into the AOP is second quarter of 2003. Miscible gas injection is planned within the blocks having established water injection, North of Crest and West Blocks. Expansion to the remaining blocks is dependent upon performance of primary production and waterflood operations. Additional recovery as a result of miscible gas injection is projected at 3-5% of the original oil in place.

4. Well Logs (20 AAC 25.402(c)(7))

   Well logs for the proposed injection wells are on file with the Commission.

5. Mechanical Integrity (20 AAC 25.402(c)(8))

   All newly drilled and converted injection wells have been completed in accordance with 20 AAC 25.412, thus satisfying mechanical integrity requirements. The casing programs for S-l01i, S-104i, S-107i, S-110i, S-112i, and S-114Ai were permitted and completed in accordance with 20 AAC 25.030. Injection well tubulars have premium threads to prevent tubing leaks and maintain integrity during injection of enriched gas.

Cement bond logs (ultra sonic imaging tool) run in Wells S-104i and S-112i indicate good cement bond across and above the Kuparuk River Formation. The Commission has approved water-flow logs completed in Wells S-l0li, S-107i and S-114Ai to confirm injection containment into the target zone. BPXA has applied for conversion of S-110 from production to injection status. Evidence of sufficient cement integrity is required prior to approval.

6. Injection Fluid and Rates (20 AAC 25.402(c)(9))

a. Produced Water: The Aurora waterflood project uses produced water from GC-2. The composition of GC-2 produced water and compatibility issues were addressed in the original AIO 22 application. Maximum water injection capacity at AOP is estimated at 40,000 BPD.

b. Miscible Hydrocarbon Gas: The proposed project requests approval for injection of enriched hydrocarbon gas from the Prudhoe Bay Central Gas Facility. No compatibility issues are anticipated in the formation or confining zones. Planned maximum enriched gas injection at AOP is estimated at 20 million SCF per day.

c. Source Water: Source water from the Prince Creek Formation may be used to supplement water injection if compatibility between Prince Creek Formation water and AOP formation fluids can be demonstrated.

d. Lean Gas: Approval was requested to inject lean produced gas for reservoir pressure maintenance. Compatibility with the formation is not an issue as the gas is of similar composition to AOP produced gas.

e. Other Fluids: Other fluids proposed for injection from time to time include:

1. Non-hazardous water collected from PBU reserve pits, well house cellars and standing ponds, and
2. Tracer fluids to monitor reservoir performance.

7. Injection Pressures (20 AAC 25.402(c)(10))

Enriched gas and water injection operations at the AOP are expected to be above the Kuparuk River Formation parting pressure to enhance injectivity and improve recovery of oil. Maximum proposed surface injection pressure is 2800 psi for water and 3800 psi for gas.

8. Fracture Information (20 AAC 25.402(c)(11))

With a maximum surface water injection pressure of 2800 psi, the injection gradient will be 0.85 psi/ft, assuming no friction losses, which will not propagate fractures through the confining layers. The overlying Kalubik and HRZ shales, which have a combined thickness of approximately 110 feet, have a fracture gradient 0.8 to 0.9 psi/ft. The underlying Miluveach/Kingak shale sequence has a fracture gradient of approximately 0.85 psi/ft.

9. Water Analysis (20 AAC 25.402(c)(12))

The compositions of injection water and AOP connate water were provided in Exhibit IV-4 of the original AIO application. Water analysis from the nearby Milne Point Prince Creek Formation was provided in the April 28, 2003 application for rehearing.

10. Aquifer Exemption (20 AAC 25.402(c)(13))

On July 11, 1986, the Commission approved Aquifer Exemption Order 1 ("AEO 1") for Class II injection activities within the Western Operating Area of the Prudhoe Bay Unit. The AOP is entirely within the area covered by AEO-1.

11. Hydrocarbon Recovery and Reservoir Impact (20 AAC 25.402(c)(14))

The Commission denied BPXA's original application because insufficient technical information was supplied to support that the injectant would remain miscible throughout the planned flood area. BPXA fully addressed the concerns within the April 28, 2003 application for re-hearing.

Reservoir Depletion Plan and Field Development:

Due to high structural complexity, phased development of the AOP was pursued. Reservoir surveillance from a period of primary production helped define reservoir compartments and appropriate placement of water injectors. Miscible gas injection will begin in the West and North of Crest Blocks where water injection has been established.

Water injection in the South East of Crest Block is planned with conversion to injection of S-110 and S-112. Production within the Crest Block began in mid March 2003 with startup of wells S-115 and S-117. An injector will be considered for the Crest Block dependent upon primary production results. A local water injection booster pump is being evaluated to increase water injection support within the AOP.

Reservoir Pressure and Minimum Miscibility ("MMP"): Slim tube experiments with Prudhoe Bay enriched gas injectant and Aurora oil yielded a MMP of 2700 psi. BPXA provided an update of the well shut-in pressure measurements and evaluated the information for validity. All shut-in reservoir pressure measurements were above 2700 psi. Reservoir simulation indicates the average field pressure is above 3100 psi, with about 90% of the field above the MMP. Areas below the MMP are limited to local producing well areas.

Effect of Delayed Depletion: Reservoir mechanistic studies performed by BPXA show insignificant reserve loss from delayed waterflood if the average reservoir pressure is maintained above 2400 psi. MI injection was simulated for two separate average reservoir pressure cases. The runs at 3400 psi and 2700 psi show comparable incremental recoveries.

Reservoir Voidage: Water injection has recently increased and is equal to or slightly exceeds reservoir withdrawal in both the North of Crest and West Blocks. GOR's within the waterflood area have continued to decline, suggesting good waterflood support. Injection line repair has resulted in increased water injection rates and associated increased wellhead injection pressures. Planned water injector and MI conversions and the potential water injection booster pump will provide further voidage replacement.

Reservoir Surveillance: BPXA supplied a plan to acquire reservoir pressure measurements in 2003. The number of reservoir pressures planned exceeds that required by CO457, and adequately addresses the issues raised by the Commission within AIO 22B.

Lean Gas Injection: Approval of lean gas injection is premature at this time. Insufficient information was provided regarding impact upon ultimate recovery. Administrative approval allowing lean gas injection may be sought at a later date when plans and recovery benefits are better defined.

12. Mechanical Condition of Adjacent Wells (20 AAC 25.402(c)(15))

Mechanical integrity has been established for the wells within ¼ mile radius of proposed injectors. Mechanical integrity is based upon calculated cement tops being at an adequate height above the injection zone to prevent fluid that is injected into the AOP from flowing into other zones or to the surface.

CONCLUSIONS:

1. The application requirements of 20 AAC 25.402 have been met.
2. There are no freshwater strata in the AOP area.
3. The proposed water and miscible gas injection operations will be conducted in permeable strata and will involve injection above the parting pressure of the Kuparuk Formation in the AOP.
4. Injection pressures up to 2800 psi for water and 3800 psi for gas will not propagate fractures through the confining interval. Injected fluids will be confined within the appropriate receiving intervals by impermeable lithology, cement isolation of the wellbore and appropriate operating conditions.

5. Enriched gas injection from the Prudhoe Bay Unit will preserve reservoir energy and enhance ultimate recovery within the North of Crest and West Blocks. Expansion will be dependent upon the production performance under primary recovery and waterflood and the success of the miscible injection within the North of Crest and West Blocks.
6. Reservoir surveillance, operating parameter surveillance and mechanical integrity tests will demonstrate appropriate performance of the enhanced oil recovery project or disclose possible abnormalities.
7. Fluids approved for injection must be compatible with the AOP Formation.
8. Depletion plan update and approval are needed prior to beginning injection of immiscible hydrocarbon gas.
9. The current average reservoir pressure is above the minimum miscibility pressure of 2700 psi. Though some producers are below this pressure, the enriched gas will remain miscible within the flood front provided the average reservoir pressure remains above this pressure.
10. BPXA's depletion strategy and development plan for the coming year will provide improved reservoir understanding and are designed to result in greater ultimate recovery.

NOW, THEREFORE, IT IS ORDERED THAT:

1. AIO 22A is withdrawn.
2. This order supersedes AIO 22 issued September 7, 2001 (as corrected September 17, 2002).
3. Rules 2, 3, and 8 of AIO 22 are revised and Rule 9 of AIO 22 is added.
4. Underground injection of fluids pursuant to the projects described in BPXA's application for AIO 22, application of December 9, 2002 for MI injection, and rehearing request of April 28, 2003 is permitted in the following area, subject to the conditions, limitations, and requirements established in the rules set out below and statewide requirements under 20 AAC 25 (to the extent not superseded by these rules, Conservation Order 457, or subsequent amendments).

Umiat Meridian

Township	Range	Sections
T11N	R12E	N ½ Sec. 3
T12N	R12E	S ½ Sec 17; SE ¼ Sec 18; E ½ Sec 19; All Sec 20; All Sec 21;W 1/2NW 1/4,S ½ Sec 22; SW ¼ Sec 23; SW ¼ Sec 25; All Sec 26; All Sec 27; All Sec 28; N ½, Se ¼ Sec 29; E ½ Sec 32; All Sec 33; All Sec 34; All Sec 35; N ½, SW ¼ Sec 36

Rule 1 Authorized Injection Strata for Enhanced Recovery (Source AIO 22)

Injection is permitted into the accumulation of hydrocarbons that is common to, and correlates with, the interval between 6765'- 7765' measured depth ("MD") in the Mobil Oil Corporation Mobil-Phillips North Kuparuk State No. 26-12-12 well.

Rule 2 Injection Pressures (Amended this Order AIO 22B)

The injection operations shall not allow fractures to propagate into the confining intervals. Surface wellhead injection pressures shall be limited to 2800 psi for water and 3800 psi for gas.

Rule 3 Fluid Injection Wells (Amended this Order AIO 22B)

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.

The application to drill or convert a well for injection must be accompanied by sufficient information to verify the mechanical condition of wells within one-quarter mile radius. The information must include cementing records, cement quality log or formation integrity test records.

Rule 4 Monitoring the Tubing-Casing Annulus Pressure Variations (Source AIO 22)

The tubing-casing annulus pressure and injection rate of each injection well must be checked at least weekly to confirm continued mechanical integrity.

Rule 5 Demonstration of Tubing-Casing Annulus Mechanical Integrity (Source AIO 22)

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.

Rule 6 Notification of Improper Class II Injection (Source AIO 22)

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 operator's responsibility.

Rule 7 Other conditions (Source AIO 22)

a. It is a condition of this authorization that the operator complies with all applicable Commission regulations.
b. The Commission may suspend, revoke, or modify this authorization if injected fluids fail to be confined within the designated injection strata.

Rule 8 Administrative Action (Amended this Order AIO 22B)

Unless notice and public hearing is otherwise required, the Commission may administratively waive the requirements of any rule herein 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 freshwater.

Rule 9 Authorized Fluids for Enhanced Recovery (New rule this Order AIO 22B)

The fluids authorized for injection and conditions of the authorization are as follows:

a. produced water from the AOP or Prudhoe Bay Unit processing facilities;
b. source water from the Prince Creek formation provided that the water is shown to be compatible with the AOP formation and administrative approval to inject is obtained from the Commission;
c. enriched hydrocarbon gas processed within the Prudhoe Bay Unit processing facilities, with the following conditions:
    1. reservoir pressure must be maintained to ensure miscibility of the injectant, and
    2. expansion of injection outside of the North of Crest and West Blocks must be administratively approved prior to long-term injection;
d. immiscible hydrocarbon gas from the AOP or Prudhoe Bay Unit processing facilities provided that Commission approval of the associated depletion strategy and surveillance plans is obtained prior to start of injection;
e. tracer survey fluid to monitor reservoir performance; and
f. non-hazardous filtered water collected from AOP well house cellars and well pads.

DONE at Anchorage, Alaska and dated May 6, 2003.

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/s/Sarah Palin, Chair
Alaska Oil and Gas Conservation Commission

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

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/s/Randy Ruedrich, Commissioner
Alaska Oil and Gas Conservation Commission