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

Re: THE APPLICATION OF BPXA EXPLORATION (ALASKA) INC. for an order allowing underground injection of fluids for enhanced oil recovery in Borealis Oil Pool, Prudhoe Bay Field, North Slope, Alaska	**))))**	**Area Injection Order 24A Prudhoe Bay Field, Borealis Oil Pool April 22, 2005**

IT APPEARING THAT:

1. In correspondence dated January 12, 2005 BPXA requested the Commission to modify Area Injection Order No. 24 to allow injection of miscible hydrocarbons and Prince Creek Formation water to enhance oil recovery from the Borealis Oil Pool.
2. The Commission published notice of opportunity for public hearing for the revision of Area Injection Order No. 24 in the Anchorage Daily News on February 8, 2005.
3. On February 25, 2005 BPXA, in response to a Commission request, provided additional information and revisions to some exhibits in the January 12, 2005 correspondence.
4. The Commission received no protests to BPXA's application for modification of Area Injection Order No. 24 and no requests for public hearing.

FINDINGS:

1. <u>Project Area and Pool Description:</u>

a. Proposed Injection Area: BPXA requested authorization to inject fluids for the purpose of enhanced recovery operations in the affected area of CO 471, which defines pool rules for the Borealis Oil Pool (“BOP”), Prudhoe Bay Field, North Slope Alaska.

b. Borealis Oil Pool: The BOP is defined as the accumulations of hydrocarbons common to and correlating with the interval between 6534' and 6952' measured depth ("MD") in the West Kuparuk State 1 well.

2. **Operators/Surface Owners:**

BPXA provided all operators and surface owners within one-quarter mile of the BOP with a copy of the application for injection. Those operators are: BPXA, operator of Milne Point Unit and Prudhoe Bay Unit, ConocoPhillips Alaska, Inc., operator of the Kuparuk River Unit. The State of Alaska, Department of Natural Resources is the only affected surface owner.

3. **Description of Operation:**

a. Proposed MI Expansion: BPXA is requesting Commission approval to allow expansion of miscible gas injection operations throughout the BOP. Existing pilot injection is currently allowed in wells L-105i, L-108i and V-100i. The project involves the cyclical injection of water alternating with injection of enriched hydrocarbon gas (“WAG”) into the oil column of the Kuparuk River Formation of the BOP. The miscible gas injection (“MI”) to be used in the project will be comprised of hydrocarbon gas, enriched with intermediate hydrocarbons, principally ethane and propane.

Borealis injection wells are drilled from existing L, V and Z-Pads and may be converted to allow WAG injection. Additional injectors may be drilled from these pads and potentially from a future I-Pad currently under evaluation. The Borealis MI injection project includes an MI pipeline from the existing Z-Pad and trunk and lateral distribution systems at each pad. The only surface modifications required to implement the Borealis EOR project will be to the header riser spools.

A request was made May 28, 2004 to convert wells L-105i, L-108i and V-100i to implement an EOR MI injection pilot program. The Commission approved pilot operations for a three-month period and the wells were converted to MI injection on June 29, 2004. Subsequent approvals have extended the project to the current time. Well L-108i, due to a well tie-in timing issue, was not used in the Pilot.

The main objectives of the pilot were to evaluate available MI system injection pressure and reservoir gas injectivity. Injectivity was confirmed as sufficient to handle the rates needed to provide both voidage replacement and EOR sweep in an effective manner.

b. Proposed Prince Creek Water Injection: BPXA is requesting approval to allow injection of Prince Creek source water as needed for pressure support. Currently, produced water is being supplied from existing infrastructure to support the BOP waterflood. Evaluation continues for use of Prince Creek (Ugnu and Sagavanirktok) as supply for future waterflood. The W-400 well startup October 15, 2004 proves Prince Creek deliverability of at least 20,000 BWPD. The Borealis Owners intend to inject water at a voidage replacement ratio greater than one to restore reservoir pressure. The additional Prince Creek source water will be helpful to meet this goal.

4. **Current Development at Borealis:**

Drilling commenced July 2001 with production startup in November 2001. Water injection started in June 2002. Borealis production is commingled on the surface with IPA and Orion production on L, V, and Z-Pads and processed at GC-2. Listed below is additional information describing the BOP as of December 1, 2004. More detail can be found in BPXA's application.

- 17 wells drilled at V-Pad - 10 oil producers- 4 water injectors - 1 WAG injectors – 2 abandoned for sidetrack
- 23 wells drilled at L-Pad - 14 oil producers - 8 water injectors - 1 WAG injector
- 2 wells drilled at Z-Pad - 1 oil producer - 1 well shut-in
- Oil Production Rate: 21,300 BOPD
- Gas Production Rate: 17,000 MSCFD
- Water Production Rate: 18,000 MBWPD
- Water Injection Rate: 55,300 BWPD
- MI Injection Rate: 0 MMSCFD
- Cumulative Oil Production: 30.3 MMSTBO
- Cumulative Gas Production: 26.4 MMSCF
- Cumulative Water Production: 9.5 MMSTB
- Cumulative Water Injection: 33.5 MMSTB
- Cumulative Gas Injection: 0.6 BCF

BPXA is currently evaluating a proposed expansion of the Z-Pad, which would accommodate additional development of the southern expansion area. Additionally, BPXA is considering development of the northwest portion of the BOP from a proposed I-Pad location.

5. <u>Geologic Information:</u>

a. <u>Available Data:</u> Production, seismic and well data have been used to characterize the BOP.

b. <u>Stratigraphy:</u> The affected reservoir is the early Cretaceous-aged Kuparuk River Formation ("Kuparuk"), which consists of very fine to medium grained quartz-rich sandstone, interbedded with siltstone and mudstone.

Within the BOP, BPXA divides the Kuparuk into four stratigraphic intervals that are designated, from oldest to youngest, A, B, C and D. The C interval contains the primary reservoir sands of the BOP, and secondary accumulations occur in the A and B sands.

c. <u>Structure Overview</u>: Within the BOP, the top of the Kuparuk lies between 6,200 and 6,900 feet true vertical depth subsea ("TVD"). The structure of interest is a northwest-to-southeast trending antiform that is broken by two sets of faults: an older set of northwest-southeast trending faults and a younger set of north-south striking faults. The complexity of faulting, and production data from the BOP demonstrate the reservoir is divided into separate fault bounded compartments.

d. Trapping Mechanism: Hydrocarbons are structurally and stratigraphically trapped within the Borealis Oil Pool. The oil accumulation is bounded to the southwest by northwest and north-south trending faults and the oil/water contact ("OWC"). To the northeast, the accumulation is limited by the down-dip intersection of the top of the reservoir with the OWC and with a series of north-south trending faults. To the southeast, the reservoir is truncated by an intra-formational unconformity and onlap onto the Prudhoe high. To the northeast, the reservoir sand intervals degrade to non-reservoir quality.

e. Confining Intervals: The impermeable shales of the Kalubik Formation and the HRZ have a combined thickness of approximately 110 feet and provide upper confinement for the Kuparuk reservoir sands within the BOP. Lower confinement is provided by shale and siltstone of the Miluveach and Kingak Formations.

6. Well Logs:

The logs of existing injection wells are on file with the Commission.

7. Mechanical Integrity:

All wells drilled and converted for injection service have been completed in accordance with 20 AAC 25.412, thus satisfying the mechanical integrity requirements as required by 20 AAC 25.402. The casing program for planned conversions of existing water injection wells was permitted and completed in accordance with 20 AAC 25.030.

A state witnessed MIT is required on wells prior to injection startup. In drilling all Borealis injection wells, the casing is pressure tested in accordance with 20 AAC 25.030. Injection well tubing/casing annulus pressures will be monitored and recorded on a regular basis. The Borealis Oil Pool injection wells will be designed to comply with the requirements specified in 20 AAC 25.412.

8. Injection Fluids:

Type of Fluid/Source: BPXA is requesting authorization to inject the following fluids in the Borealis Oil Pool within the Prudhoe Bay Field:

- Produced water from Borealis or Prudhoe Bay Unit production facilities for the purposes of pressure maintenance and enhanced recovery;
- Miscible Injectant from the Prudhoe Bay Central Gas Facility.
- Source water from the Prince Creek Formation;
- Non-hazardous water collected from well house cellars and standing ponds;
- Source water from a Seawater Treatment Plant.

9. Injectant Composition and Compatibility with Formation:

As previously approved by the Commission, produced water from GC-2 is used as the primary water source for Borealis injection. Injection performance, core, log and pressure-buildup analyses indicate no significant problems with clay swelling or compatibility with in-situ fluids.

BPXA analysis of cores from the BOP wells indicates relatively low clay content. Petrographic analysis indicates that clay volumes in the better quality sand sections (>20 md) are in the range of 3 - 6%. Clay volumes increase to approximately 6 - 12% in rock with permeabilities in the range of 10 - 20 md. Below 10 md, clay volumes increase to a range of 12 - 20%. Most of the identified clay is present as intergranular matrix, having been intermixed with the sand through burrowing. The overall clay composition is a mixture of roughly equal amounts of kaolinite, illite and mixed layer illite/smectite. No chlorite was reported during petrographic analysis.

The presence of iron-bearing minerals suggests that the use of strong acids should be avoided in breakdown treatments, spacers, etc.

Water from the seawater treatment plant has been successfully used for injection within the Kuparuk of the Pt. McIntyre Oil Pool.

Geochemical modeling indicates that a combination of GC-2 produced water and connate water is likely to form calcium carbonate and barium sulfate scale in the production wells and downstream production equipment. Scale precipitation will be controlled using scale inhibition methods similar to those used at Kuparuk River Unit and Milne Point Unit.

Miscible gas is a hydrocarbon with similar composition to reservoir fluids in the BOP therefore no compatibility issues are anticipated with the formation or confining zones.

The composition of injection water from the Prince Creek aquifer is expected to fall within the range of Well W-400 and MPF-02 produced water compositions, less than 10,000-ppm total dissolved solids. Milne Point Unit F-Pad Prince Creek source water has been injected since 1996 into the Milne Point Kuparuk Reservoir, lithologically similar to the BOP, with no apparent formation damage. A single well chemical tracer test in BOP well L-122 conducted using 640 barrels of Prince Creek Source water did not detect any formation damage.

10. **Injection Volumes and Pressures:** Maximum expected water injection rates are 90 MBWPD, with maximum surface and bottom hole pressures of 3000 psi and 5000 psi, respectively. Maximum expected MI rates are 70 MMSCFD, with maximum surface pressures of 3800 psi.

11. **Fracture Information:**

The L-101 well was fracture stimulated in the BOP Kuparuk C sand at the Borealis Oil Pool, with a formation breakdown pressure of 4290 psi, which calculates to a fracture gradient of 0.65 psi/ft at initial reservoir conditions. This data agrees with data from offset fields containing wells completed in the Kuparuk.

The Kalubik and HRZ shales overlie the Kuparuk at the Borealis Pool with a combined thickness of approximately 110 feet. The HRZ is a thick shale sequence, which tends to behave as a plastic medium and can be expected to contain significantly higher pressures than sandstones of the Kuparuk. Mechanical properties determined from log and core data for the HRZ and Kalubik intervals indicate a fracture gradient from approximately 0.8 to 0.9 psi/ft. Dipole Sonic evaluations of these strata have measured values equal to or greater than 0.99 psi/ft confining stress.

The Kuparuk is underlain by the Miluveach/Kingak shale sequence. A leakoff test in the Kingak shale formation demonstrated leakoff at a gradient of approximately 0.85 psi/ft.

The expected maximum injection pressure in the Borealis wells will not initiate or propagate fractures through the confining strata, and, therefore, will not allow injection or formation fluid to enter any freshwater strata. There is no evidence of injection out of zone for similar Kuparuk waterflood operations on the North Slope. Water injection operations at the Borealis Pool are expected to be above the Kuparuk parting pressure to enhance injectivity and improve recovery of oil. Fracture propagation models confirm that injection above the parting pressure will not exceed the integrity of the confining zone.

12. Aquifer Exemption:

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 Borealis Pool is entirely within the area covered by AEO-1.

13. Hydrocarbon Recovery:

a. Primary and Waterflood Recovery:

Estimates for original oil in place ("OOIP") for the BOP reflect current well control, stratigraphic and structural interpretation, and rock and fluid properties. The BOP current estimate of OOIP ranges between 310 and 430 MMSTB. The extent of the range of estimates is due primarily to uncertainty in the BOP structural definition, oil water contact and reservoir net pay interval estimates. There is no free gas cap known in Borealis. Estimated associated formation gas in place ranges from 135 to 200 BSCF. Primary and waterflood oil recovery is estimated at 100-130 MMSTB based on field performance reservoir modeling. A three-dimensional geologic and dynamic flow model of the Borealis accumulation has been constructed based on detailed stratigraphic and structural interpretation. This model provides the bulk reservoir volume and porosity distribution for the BOP. The model area encompasses the known extent of the Borealis accumulation. Model results indicate recovery of 27-30% OOIP from primary and waterflood recovery mechanisms.

b. Miscible Injection Enhanced Oil Recovery

It is estimated that implementation of the proposed MI project will increase recovery by 5% to 8%, or approximately 18-25 MMSTB of oil for the project. Reservoir simulation based projections indicate the project will increase total recovery from the BOP to 35% OOIP.

A completed slim-tube experiment defines the minimum miscibility enrichment (MME) of the MI and confirms miscibility of BOP oil with the proposed MI over the expected range of reservoir pressures. The MI source is the miscible gas from the Prudhoe Oil Pool, which is richer than is required for Borealis miscibility. The experiments have been matched using a Kuparuk 12-component equation of state. BOP minimum miscibility pressure ("MMP") with the injectant is 2150 psi as determined with the equation of state and consistent with the slim-tube experiments. BOP average reservoir pressure is 3004 psi at the datum of 6600' tvdss; this is the average of pressures measured in twelve wells in August of 2004. These data are in agreement with the simulation field model estimate of 3098 psi within the BOP area boundary. Pressure measurements in a few producers are very close or slightly below the MMP; however, all pattern area pressures are above the MMP.

Project performance forecasting is based on fine-scale fully compositional reservoir simulation using Well L-101 fluid properties and whole core reservoir description. The initial MI slug size target is approximately 7% of a type injection-producer pattern polygon hydrocarbon pore volume with a nominal WAG ratio of 1.0. The cumulative target size is nominally 20% of pattern hydrocarbon pore volume or 95+ BSCF of miscible gas injection for the BOP, though MI injection parameters will be subject to adjustment as field conditions and performance indicate. After the cumulative target slug size of MI has been injected into the formation, pressure support will be maintained with water injection.

The BOP EOR gross efficiency is roughly 5 MSCF MI per barrel of EOR oil generated. Without the BOP EOR Project injection, this MI would have been injected into mature IPA EOR patterns that have a gross efficiency of 26 MSCF/STB. The Kuparuk River Oil Pool EOR project, a close analog for the proposed BOP EOR project, commenced in 1988 and has incremental EOR recovery of approximately 8-12% over waterflood. Analysis of Borealis oil samples indicates similarity to Kuparuk oil characteristics for bulk composition, wettability, and relative permeability effects.

c. Surveillance Plan;

To ensure the efficient allocation of MI for the Borealis EOR project, rate and pressure response to injection will be monitored. Production fluid compositional samples will be taken at least annually to assess pattern efficiency based on the returned MI (RMI) ratio. Offset producers of injectors currently on MI can be sampled on a more frequent basis to help determine break through times and flood efficiency. Water injection surveillance will continue using pressure falloffs and other monitoring methods as required by patterns. Injection of water and miscible gas into patterns will be evaluated on a regular basis to address pattern performance and optimum injection rates to maximize recovery.

14. <u>Mechanical Condition of Wells within a One-quarter Mile Radius of Injectors</u>

A report on the mechanical condition of each well that has penetrated the injection zone within a one-quarter mile radius of a proposed injection well has been filed with the AOGCC and is a part of the record for this order. Mechanical integrity has been established for the subject wells based on calculated cement tops being at an adequate height above the injection zone to prevent fluid that is injected into the BOP from flowing into other zones or to the surface. Static pressure and repeat formation tester data support the conclusion that the completions in offset wells beyond this radius are sufficient to contain high pressure fluids, including gas, within the BOP. Prior to any enhanced injection on wells without prior certification, wells will be demonstrated through established approved testing procedures, with a requested State Inspector present, to confirm mechanical integrity as required by 20 AAC 25.402 (e). Although injection pressure will exceed average BOP reservoir pressure, reservoir modeling indicates rapid reservoir pressure falloff away from the injector during water and MI injection. Reservoir modeling indicates a radius of pressure influence less than 1000 feet from the injector at the end of the MI cycle. Well tests are conducted routinely to monitor the flow rates from wells for purposes of reservoir management, production diagnostics and field allocation.

CONCLUSIONS:

1. The application requirements of 20 AAC 25.402 have been met.

2. An area injection order is appropriate to allow injection of water, miscible gas, and tracer fluids within the Borealis Oil Pool as described in BPXA's January 12, 2005 application under 20 AAC 25.460.

3. Information provided in this application shows that water and miscible gas injection will significantly improve recovery.

4. The annual surveillance report required by CO 471 will keep the Commission apprised of the performance of the injection project and EOR process evaluation.

5. Injection of enhanced recovery fluids at pressures above fracture gradient may be necessary in order to provide sufficient pressure support. The fracture gradient of the Borealis Oil Pool is significantly below the recorded leakoff pressures of confining shale intervals and as such the water will preferentially stay within zone.

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

7. Reservoir surveillance, operating parameter surveillance and mechanical integrity tests will demonstrate appropriate performance of the enhanced oil recovery project or disclose possible abnormalities.

8. The Borealis Oil Pool injection wells are designed to comply with the mechanical integrity requirements specified in 20 AAC 25.412.

9. BP intends to replace voidage within the BOP and reservoir pressures will be maintained above the minimum miscibility pressure.

10. The record for this order includes the hearing records and administrative files related to Area Injection Order No. 24, including administrative approvals issued under that order

NOW, THEREFORE, IT IS ORDERED:

1. This order supersedes Area Injection Order No. 24 dated May 29, 2002.

2. The underground injection of fluids pursuant to the project described in BPXA's application dated January 12, 2005 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 or the Borealis Oil Pool rules).

Umiat Meridian

T12N-R10E:	ADL 25637 Sec 13, 24
T12N-R11E:	ADL 47447 Sec 16 (SW/4 and W/2 NW/4 and W/2 SE/4), 21, 22 SW/4 and W/2 NW/4 and S/2 SE/4
	ADL 47446 Sec 17, 18, 19, 20
	ADL 28238 Sec 26 S/2 and W/2 NW/4 and SE/4 NW/4, 35, 36
	ADL 28239 Sec 27, 28, 33, 34
	ADL 47449 Sec 29, 30, 32
T11N-R11E:	ADL 28240 Sec 1, 2, 11, 12
	ADL 28241 Sec 3, 4, 9, 10
	ADL 28245 Sec 13, 14, 24
	ADL 28244 Sec 15
	ADL 28246 Sec 25
T11N-R12E:	ADL 28261 Sec 9 W/2
	ADL 47450 Sec 5 S/2, 6 S/2 and NW/4 and W/2 NE/4, 7, 8
	ADL 28263 Sec 16 W/2, 21 W/2
	ADL 28262 Sec 17, 18, 19, 20
	ADL 47452 Sec 28 W/2, 33 W/2
	ADL 47453 Sec 29, 30, 31, 32
T12N-R12E:	ADL 28259 Sec 31 W/2 and W/2 SE/4

Rule 1 Authorized Injection Strata for Enhanced Recovery

Injection of authorized fluids for purposes of pressure maintenance and enhanced recovery is permitted into strata that are common to, and correlate with, the interval between 6534' and 6952' MD in the West Kuparuk State #1 well in the Prudhoe Bay Field.

Rule 2 Authorized Injection Fluids

Fluids authorized for injection within the affected area are:

a. produced water from Borealis Oil Pool or Prudhoe Bay Unit production facilities for the purposes of pressure maintenance and enhanced recovery;

b. non-hazardous water collected from Borealis well house cellars and standing ponds;

c. tracer survey fluid to monitor reservoir performance

d. source water from a seawater treatment plant;

e. enriched hydrocarbon gas from the Prudhoe Bay Unit processing facilities, with the condition that the average Borealis Oil Pool reservoir pressure must be maintained above the minimum miscibility of the injectant; and

f. source water from the Prince Creek Formation.

Rule 3 Fluid Injection Wells

The underground injection of fluids must be through a well that has been 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 and 20 AAC 25.412.

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

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

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

Injection of fluids other than those listed in Rule 2 without prior authorization is considered improper Class II injection. Upon discovery of such an event, the operator must immediately notify the Commission, provide details of the operation, and propose actions to prevent recurrence. Additionally, notification requirements of any other State or Federal agency remain the operator's responsibility.

Rule 7 Other conditions

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

Unless notice and public hearing is otherwise required, 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 freshwater.

DONE at Anchorage, Alaska and April 22, 2005.

John K. Norman, Chairman
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).