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 to modify Area Injection Order 4C to include the Put River Sandstone Member of the Kalubik Formation in the authorized injection strata for enhanced recovery; and	)))))))	**Area Injection Order 4D** Prudhoe Bay Field Prudhoe Oil Pool Put River Oil Pool December 2, 2005
THE PROPOSAL initialed by the Commission to amend underground injection orders to incorporate consistent language addressing the mechanical integrity of wells		

IT APPEARING THAT:

1. By letter dated August 19, 2005 BP Exploration (Alaska), Inc. ("BPXA"), Operator of the Prudhoe Bay Unit, applied for a modification of Conservation Order 341D and Area Injection Order 4C to include the Put River Sandstone Member of the Kalubik Formation ("PRS") within the Prudhoe Oil Pool definition and to authorize injection for enhanced recovery purposes within the interval.
2. The Alaska Oil and Gas Conservation Commission ("Commission") published notice of opportunity for public hearing in the Anchorage Daily News on September 1, 2005.
3. On September 13 and September 30, 2005 BPXA submitted addenda addressing questions by the Commission staff concerning its application.
4. The Commission held a public hearing October 6, 2005 at the Alaska Oil and Gas Conservation Commission at 333 West 7th Avenue, Suite 100, Anchorage, Alaska 99501.
5. The Commission received no protests to or comments on BPXA's application.
6. BPXA supplied additional information as requested by the Commission on November 3, 2005.
7. On its own motion the Commission proposed to amend the rules addressing mechanical integrity in all existing orders authorizing underground injection. The Commission published notice of opportunity for public hearing on the proposal in the Anchorage Daily News on October 3, 2004 to consider amendment of underground injection orders to incorporate consistent language addressing the mechanical integrity of injection wells. A hearing was tentatively scheduled for November 4, 2004.

8. By e-mail dated October 15, 2004, BPXA suggested edits to the Commission's proposed language addressing the mechanical integrity of injection wells.
9. No protests to the Commission's proposal or requests for hearing were received, and the scheduled hearing was vacated.

FINDINGS:

1. CO 559 and CO 341E:

   The findings of Conservation Orders No. 559 and 341E are incorporated by reference.

2. Operator:

   BPXA is Operator of the property in the area in which injection is proposed.

3. Injection Strata

   BPXA requested that the PRS be added as an allowable injection stratum. The PRS is the sandstone interval that correlates with the interval 9,638 to 9,719 measured feet on the Borehole Compensated Sonic Log, Run 2, dated September 28, 1975, in the Atlantic Richfield-Exxon NGI No. 1 well. BPXA requested the addition of this sandstone interval within the definition of the Prudhoe Oil Pool.

4. Proposed Injection Area:

   The hydrocarbon-bearing interval of the PRS lies entirely within the area of the approved affected area of AIO 4C. No changes have been requested for the affected area of AIO 4C.

5. Operators/Surface Owners Notification:

   At the time of the application BPXA had not proposed a well for injection service. BPXA will provide an affidavit showing that the Operators and Surface Owners within one-quarter mile radius of each proposed injector have been notified upon application for a Permit to Drill or Application for Sundry Approval for any injection wells.

6. Description of Operation:

   The PRS is located within the Prudhoe Bay Unit and overlies the Prudhoe Oil Pool in the vicinity of Drill Sites 1, 2, 5, 6, 15, 18, NGI, and WGI. A reservoir model is currently being constructed to evaluate development options. Four vertically significant and laterally extensive sandstone lobes have been correlated within the PRS interval. There is no pressure communication between the four locally deposited sandstone lobes. Each of the lobes are laterally interbedded with shales of the Kalubik Formation. They are termed the Southern, Central, Western, Northern Lobes. The Southern and Central Lobes are saturated with black oil and the Western and Northern Lobes contain gas condensate. Development of the largest black oil accumulation, the Southern Lobe, is anticipated to include one to five production wells and one to five injection wells. Development plans for this accumulation are being evaluated.

   The Northern Lobe is in pressure communication with the gas cap of the Prudhoe Oil

Pool, and the definition of the Prudhoe Oil Pool has been expanded to include the Northern Lobe.

7. Hydrocarbons In Place and Hydrocarbon Recovery:

There are no indications of a free gas column in the Southern or Central Lobes. Estimated hydrocarbons in place are as follows:

Lobe	Estimated Oil in Place, MMSTB	Estimated Gas in Place, BCF
Southern	12.6-19.2	6.9-10.5
Central	1.1-2.7	.5-1.3
Western	n/a	69.6-104.4
Northern	n/a	108.4-160.4

Using material balance calculations for the Southern and Central Lobes, primary depletion is estimated to recover approximately 10% of the STOIP. Early screening of analog reservoirs suggests incremental recovery of 10-25% with waterflood. No discussion was provided concerning the benefits of enriched gas injection.

8. Geologic Information:

The Northern Lobe of the PRS is in depositional contact, and pressure communication with the Sag River Formation portion of the Prudhoe Oil Pool. The Commission has expanded the Prudhoe Oil Pool to include the Northern Lobe of the PRS with the issuance of CO 341E. The remaining lobes of the PRS, including the targeted waterflood development area of the Southern Lobe, are hydraulically isolated from the Prudhoe Oil Pool and each other. The Southern, Central and Western Lobes of the PRS comprise the Put River Oil Pool as defined in CO 559.

BPXA's application and Conservation Order 559 provide a discussion of the Put River Oil Pool development.

9. Well Logs:

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

10. Mechanical Integrity and Well Design of Injection Wells:

The casing programs for injectors will be permitted and completed in accordance with 20 AAC 25.030. Cement bond logs will be run on all injection wells to demonstrate isolation of injected fluids to the PRS.

11. Type of Fluid / Source:

Fluids requested for injection for the purposes of pressure maintenance and enhanced recovery are:

a) produced water from Prudhoe Bay Unit production facilities;

b) source water from the Seawater Treatment Plant;

c) fluids injected for purposes of stimulation per 20 AAC 25.280(a)(2), consistent with other North Slope field practices;

d) tracer survey fluid to monitor reservoir performance, consistent with other North Slope field practices; and

e) miscible injectant.

12. Water Composition and Compatibility with Formation:

The main fluid source will be source water from the Seawater Treatment Plant. No significant compatibility issues are anticipated between the formation and injected fluid. Analyses of core samples from Put River Formation sandstone in Prudhoe Bay Unit Well 2-14 demonstrate similar clay mineral types and proportions as those in Kuparuk River Formation reservoirs in adjacent North Slope fields. Each of the analog fields has a successful history of waterflooding and based on these comparisons the Put River Formation is not anticipated to have compatibility issues related to seawater injection.

13. Injection Rates and Pressures, Fracture Information:

The expected average surface water injection pressure for the PRS is 1800 psig. The maximum water injection pressure is 2600 psig, or 5950 psig bottom hole. The sandstone in the Southern Lobe where injection is being evaluated has 80-100 feet of Kalubik Formation above and 150-200 feet of Kingak Shale below. With the bounding shale thicknesses, the expected maximum injection pressure would not initiate or propagate fractures through the confining strata.

14. Underground Sources of Drinking Water:

No underground sources of drinking water are known to exist beneath the area covered by this order, the Eastern Operating Area of the Prudhoe Bay Unit and the Pt. McIntyre Oil Field.

15. Mechanical Integrity of Injection Wells and Wells within ¼ mile of injector:

A report on the mechanical condition of each well that has penetrated the PRS within one-quarter mile radius of a proposed injection well will be provided to the Commission with each application for a Permit to Dill or Application for Sundry Approval for an injection well.

Changes proposed by the Commission in the rules governing demonstration of mechanical integrity, well integrity failure and confinement, and administrative actions will improve clarity, reduce the potential for confusion, and better protect mechanical integrity of injection wells.

CONCLUSIONS:

1. The conclusions of CO 559 and CO 341E are incorporated by reference.
2. The application requirements of 20 AAC 25.402 have been met.
3. Initial development will target oil reserves in the Southern Lobe of the Put River Oil Pool.
4. Water injection will significantly improve recovery within the Southern Lobe of the Put River Oil Pool.
5. Further rules on depletion plans and appropriate enhanced recovery operations are

incorporated within CO 559.

6. There are no known or anticipated compatibility problems between the PRS and the requested injectants.
7. 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.
8. Injected fluids will be confined within the appropriate receiving intervals by impermeable lithology, cement isolation of the wellbore and appropriate operating conditions.
9. Reservoir and well surveillance, coupled with regularly scheduled mechanical integrity tests, will demonstrate appropriate performance of the enhanced oil recovery project or disclose possible abnormalities.
10. Revisions as proposed by the Commission are appropriate concerning the rules governing demonstration of mechanical integrity, well integrity failure and confinement, and administrative actions.

NOW, THEREFORE, IT IS ORDERED

1. Rule 1 of Area Injection Order No. 4C (corrected) is amended to include the following in the authorized injection strata for the injection of fluids described in Finding 9 of this order for purposes of pressure maintenance and enhanced recovery:
   a. the Prudhoe Oil Pool as defined in Conservation Order No. 341E;
   b. the Put River Oil Pool as defined in Conservation Order No. 559.

2. Rule 4 of Area Injection Order No. 4C (corrected) is amended to read:

<u>Rule 4 Monitoring the Tubing-Casing Annulus Pressure Variations</u>

The tubing and casing annuli pressures of each injection well must be monitored at least daily, except if prevented by extreme weather condition, emergency situations, or similar unavoidable circumstances. Monitoring results shall be documented and made available for Commission inspection.

3. Rule 5 of Area Injection Order No. 4C (corrected) is revoked.

4. Rule 6 of Area Injection Order NO. 4C (corrected) is hereby amended to read:

<u>Rule 6 Demonstration of Tubing/Casing Annulus Mechanical Integrity</u>

A Commission-witnessed mechanical integrity test must be performed after injection is commenced for the first time in a well, to be scheduled when injection conditions (temperature, pressure, rate, etc.) have stabilized. Subsequent tests must be performed at least once every four years thereafter (except at least once every two years in the case of a slurry injection well). The Commission must be notified at least 24 hours in advance to enable a representative to witness mechanical integrity tests. Unless an alternate means is approved by the Commission, mechanical integrity must be demonstrated by a tubing/casing annulus pressure test using a surface pressure of 1500 psi or 0.25 psi/ft multiplied by the vertical depth of the packer, whichever is greater, that shows stabilizing pressure and does not change more than 10 percent during a 30-minute period. Results of mechanical integrity tests must be readily available for Commission inspection.

5. Rule 7 of Area Injection Order No. 4C (corrected) is amended to read:

Rule 7 Well Integrity Failure and Confinement

Whenever any pressure communication, leakage or lack of injection zone isolation is indicated by injection rate, operating pressure observation, test, survey, log, or other evidence, the Operator shall notify the Commission by the next business day and submit a plan of corrective action on a Form 10-403 for Commission approval. The Operator shall immediately shut in the well if continued operation would be unsafe or would threaten contamination of freshwater, or if so directed by the Commission. A monthly report of daily tubing and casing annuli pressures and injection rates must be provided to the Commission for all injection wells indicating well integrity failure or lack of injection.

6. Rule 9 of Area Injection Order No. 4C (corrected) is amended to read:

Rule 9 Administrative Action

Unless notice and public hearing are otherwise required, the Commission may administratively waive or amend any rule stated above 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 fluid movement outside of the authorized injection zone.

DONE at Anchorage, Alaska and dated December 2, 2005.

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John K. Norman
Chairman

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Daniel T. Seamount, Jr.
Commissioner

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).