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 amendment to AIO-10A to allow for underground injection of fluids for enhanced oil recovery in Sag River Oil Pool.	**Area Injection Order No. 10-B** **Milne Point Field - Milne Point Unit** **Sag River Oil Pool** **Kuparuk River Oil Pool** **Schrader Bluff Oil Pool** **Date: April 23, 2002**

IT APPEARING THAT:

1. By application dated February 6, 2002, and received by the Alaska Oil and Gas Conservation Commission ("Commission") on that same day, BP Exploration (Alaska) Inc. ("BP") requests that the Commission amend Area Injection Order No. 10-A ("AIO 10-A") to authorize the injection of fluids for enhanced recovery in the Sag River Oil Pool ("SROP") within the Milne Point Unit ("MPU").
2. The Commission published notice of opportunity for a public hearing in the Anchorage Daily News on February 21, 2002.
3. The Commission did not receive a protest or written request for a public hearing.
4. BP provided additional information requested by the AOGCC by letter dated March 29, 2002, and electronic mail dated April 12, 2002 and April 16, 2002.
5. BP provided sufficient information on which to make a ruling without need for a hearing.

FINDINGS:

1. Authority 20 AAC 25.460

   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. Pertinent Commission Orders

   Three oil pools are encompassed in total or in part by the MPU. These pools and major conservation orders governing them are discussed below:

a) Kuparuk River Oil Pool ("KROP"), Kuparuk River Field, with current applicable pool rules set forth in Conservation Order ("CO") 432A (August 11, 1999), and area defined in CO 349A (December 23, 1996).

b) Schrader Bluff Oil Pool ("SBOP") with pool rules set forth in CO 255 (July 2, 1990) and CO 283 (December 30, 1991).

c) Sag River Oil Pool ("SROP") with pool rules set forth in CO 423 (May 6, 1998)

Area Injection Order 10-A (October 29, 2001) and Administrative Approval to AIO-10-A ("AIO10-A.001") issued December 14, 2001 provide the current applicable rules governing enhanced recovery operations within the Milne Point Unit. Only the KROP and SBOP are covered by these rules. BP requests that the Commission amend AIO 10-A to authorize the injection of fluids for enhanced recovery in the Sag River Oil Pool ("SROP").

Area Injection Order 10 ("AIO-10"), originally issued September 19, 1986, authorized enhanced recovery injection operations within the ("KROP"). By an order dated December 30, 1991, AIO 10 was amended to allow enhanced recovery operations for the Schrader Bluff Oil Pool ("SBOP") within MPU. AIO 10 was amended for expansion of the effected areas of enhanced recovery operations on May 3, 1994 and November 13, 1995.

AIO-10A approved October 29, 2001, superseded AIO-10 for enhanced recovery operations within the Milne Point Unit. AIO 10-A adopted rules applicable to each of the KROP and SROP in the MPU, specifically as regards the enhanced recovery fluids approved for injection within the separate pools. For the KROP, AIO10-A approved injection of miscible gas injectant ("MI"), including NGLs imported from the Prudhoe Bay Unit for purposes of pressure maintenance and enhanced recovery within the KROP. The area approved for injection activities coincided with the Milne Point Unit boundaries at the time of approval.

Administrative approval AIO10-A.001, issued December 14, 2001 allowed for non-hazardous treated wastewater from the Milne Point Wastewater Treatment Plant and non-hazardous water collected from MPU reserve pits, well house cellars and standing ponds as an authorized fluid for the purpose of enhanced oil recovery in the KROP and SBOP.

Aquifer Exemption Order 2 ("AEO-2") was issued by the Commission on July 8, 1987 exempted freshwater aquifers underlying the Milne Point Unit for Class II injection activities pursuant to 20 AAC 25.440. When AEO-2 was issued in 1987, it coincided with the boundaries of AIO-10 at that time. BP requested on March 28, 2002 that the area for AEO-2 be expanded to include MPU leases that are wholly or partially included in the Milne Point Unit.

3. SROP Development and Injection Plan Summary

   BP completed conventional producers with electrical submersible pumps ("ESPs") in the SROP to test economic and development potential. These wells were not able to produce for long periods of time due to high gas-oil ratios and poor pump performance. All but three of the wells that penetrated the Sag River Formation have been re-completed to the KROP or have been suspended or abandoned.

   In 2001, wells MPF-33A and MPF-73A were horizontally sidetracked with coiled tubing, and completed with jet pumps for artificial lift. The productivity of the wells and the performance of the jet pumps have been favorable. Injection of water into MPF-73A to provide pressure support at MPF-33A is being proposed. Without water injection, reservoir pressure and production rate will decline. BP has also requested the use of gas for miscible and lean gas injection.

   BP has stated that if secondary support between MPF-33A and MPF-73A can be stabilized at a reasonable rate, additional fault blocks near C Pad may be developed.

4. Project Area (20 AAC 25.402(c)(1)), Pool Description (Pool Information (20 AAC 25.402(c)(5))

   For this amendment to AIO-10A, BP is requesting the addition of the Sag River Oil Pool as defined in CO 423 to be included.

   a) Proposed Injection Area for SROP: The requested project area includes that portion of the Sag River Oil Pool, Milne Point Field as specified in CO 423.

   b) Sag River Oil Pool: The SROP is defined in CO 423 as the accumulation of hydrocarbons that are common to and correlate with the interval between the measured depths of 8810 and 8884 feet of Milne Point Unit A-01.

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

   BP has provided all designated operators within one-quarter mile of the MPU with a copy of the application for amendment of AIO 10-A. Those operators are: BP, operator of MPU and Prudhoe Bay Unit, Phillips Alaska, Inc., operator of the Kuparuk River Unit, and J. Andrew Bachner, operator of leases ADL 389717 and ADL 389718. The State of Alaska, Department of Natural Resources is the only affected surface owner.

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

   The Sag River injection pilot project currently consists of one active primary producer, MPF-33A and an idle injection well, MPF-73A, which is awaiting approval to provide secondary support for MPF-33A. Injection of source water from the Prince Creek Formation is currently planned. If waterflood is successful in providing pressure support, lean gas injection and potentially miscible gas injection may be tested.

BP has stated that if waterflood support between MPF-33A and MPF-73A can be stabilized at a reasonable rate, additional fault blocks near C Pad may be developed. Facilities are in place for injection into F-73A.

7. Geologic Information (20 AAC 25.402(c)(6))

The following is a summary of the geologic information for the SROP within the MPU.

a) Reservoir Interval for Injection Project: The SROP is defined as the accumulation of hydrocarbons that is common to and correlates with the interval between the measured depths of 8810 and 8884 feet of Milne Point Unit A-01.

b) Available Data: Well and 3-D seismic data have been used to characterize the SROP accumulation. Twelve wells have penetrated the SROP within the boundaries of the MPU.

c) Stratigraphy: The affected reservoir is a portion of the Sag River Formation, which consists of a thin, marine shelf sand that is late Triassic to early Jurassic in age. This shelf sand averages 77 feet in thickness, and it has been extensively bioturbated, resulting in relatively poor reservoir rock.

Within the SROP, BP has divided the Sag River Formation into four zones that are informally named, from oldest to youngest, A, B, C and D. Zones A, C, and D are characterized by low porosity and permeability. Zone B contains the only reservoir-quality rock. This zone averages 30 feet in gross thickness, with net pay ranging from 9 to 18 feet. Porosity within Zone B ranges up to 21 percent, and permeability measured by core ranges from 0.1 to 23 millidarcies, with an average of 1.7 millidarcies. Permeability thickness within Zone B ranges from 30 to 68 millidarcy-feet.

d) Structure Overview: Within the MPU, the top of the Sag River Formation within the area of interest lies between 8550 feet and 9500 feet true vertical depth sub-sea ("TVDss"). The structure of interest is a narrow anticline that trends northwest through the center of the unit. The crest of the anticline is broken by a series of northwest-trending, down-to-the-southwest normal faults, that have vertical displacements ranging from 100 to over 700 feet. The anticline is broken into a series of small compartments by two sets of additional, smaller normal faults that trend northwest and east-northeast. These additional faults range up to 150 feet in vertical displacement, and they are an important influence on distribution of oil within the Sag River Formation at Milne Point. Because of the relatively thin (typically 9-18 feet thick) pay zone, a fault of less than 50 feet displacement can trap hydrocarbons.

e) Trapping Mechanism: Hydrocarbons are structurally trapped within the SROP. Oil has accumulated up-dip against the main northwest-trending normal fault zone that cuts the crest of the anticline. Secondary controls on hydrocarbon distribution are the smaller north-northeast trending faults and structural dip, which ranges from 2 to 5 degrees to the northeast. The smaller faults create separate compartments within the SROP, as is evidenced by the separate oil-water contacts of 9150, 9050 and 8950 feet TVDss that are described in the written testimony provided by BP in support of CO 423.

f) Confining Interval: Upper confinement for the SROP is provided by the Kingak Formation, an impermeable, Jurassic-aged shale that is approximately 1000 feet thick within the proposed injection area.

   Lower confinement is provided by the Shublik Formation, a 150 to 200 foot-thick interval of Triassic-aged siltstone, shaley phosphatic limestone and shale.

8. Well Logs (20 AAC 25.402(c)(7)): The logs of existing injection wells are on file with the Commission.

9. Mechanical Integrity (20 AAC 25.402(c)(8)): Only MPF-73A is currently planned as an injector. It has been pre-produced using a jet pump but is now shut-in. BP has performed a successful mechanical integrity test ("MIT") on the well. A state witnessed MIT will be needed on the well prior to injection startup. Adequate cement isolation of Sag River Formation is apparent from cement bond log dated March 1, 2001. Future wells used for injection will be cased and cemented in accordance with 20 AAC 25.412. In drilling all MPU 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 MPU SROP injection wells will be designed to comply with the requirements specified in 20 AAC 25.412.

10. Injection Fluids (20 AAC 25.402(c)(9)). BP is requesting approval for the following fluids for injection into the SROP.

    a) Source Water and Produced Water: The produced and source water (from the Prince Creek Formation) injected in the SROP has been described in prior AIO 10 applications. The approximate water injection volume needed for the first SROP injector MPF-73A is 2000 barrels of water per day ("BWPD") with peak injection of 5000 BWPD. Additional volumes may be needed to make up reservoir voidage or as additional injectors and producers are added.

       Source water is obtained from the Prince Creek Formation in the F Pad and K Pad areas from dedicated source water production wells. Produced water from the KROP, the Schrader Bluff Oil Pool ("SBOP") and the SROP is gathered and separated from the oil and gas at the MPU Central Facilities Processing Plant ("CFP"). Produced water may also contain trace amounts of scale inhibitor, corrosion inhibitor, emulsion breakers and other products used in the production and separation process.

       No direct tests have been performed to evaluate if plugging or clay swelling will be problematic. An objective of the initial pilot project is to determine if compatibility will be an issue between the source water and the Sag River Formation fluids.

    b) Miscible Hydrocarbon Gas: The miscible hydrocarbon injectant ("MI") will be a blend of the produced gas from MPU and natural gas liquids ("NGLs") imported from the Prudhoe Bay Unit. The specific blend of gas and NGLs will be regulated to ensure that miscibility between the injected gas and the reservoir fluids is maintained. The estimated composition of the miscible hydrocarbon gas is based on a blend ratio of 4.512 MSCF lean gas/bbl NGL for a minimum miscibility pressure of approximately 2900 psia. BP proposes to inject miscible gas only if it is economically competitive with injection of miscible gas in the KROP. Fluid compatibility problems are not anticipated with the miscible hydrocarbon gas.

While the injection of lean gas within the SROP has been adequately supported by reservoir simulation results presented in application of pool rules (CO 423), BP has not provided sufficient information about the miscibility or the efficiency of use of the available MI within the SROP. Facilities currently in place at F Pad will allow only the above stated blend of MI, although lean gas injection may at times be available on an intermittent basis.

c) Other Fluids: the following other incidental fluids might be injected into the SROP at some time during the life of the project to enhance recovery of oil and gas:

- Seawater to thermally fracture gas injection wells – a stimulation procedure using 20,000 – 40,000 gallons per well
- Solution gas associated with oil production – re-injected for reservoir pressure maintenance
- Tracer survey fluid – to monitor reservoir performance
- Non-hazardous treated wastewater from the Milne Point Wastewater Treatment Plant and non-hazardous water collected from MPU reserve pits well house cellars and standing ponds.

11. Injection Pressures (20 AAC 25.402(c)(10)): Surface injection pressures are dependent on fluid type. The estimated average and maximum injection pressure for the project is as follows:

	Surface Operating Pressure PSIG	
Service	Maximum	Average
Source Water Injection	3600	3500
Produced Water Injection	3400	3000
Gas Injection	5000	4500

12. Fracture Information (20 AAC 25.402(c)(11)): BP indicates injection pressures above fracture gradient may be required to provide adequate pressure support within the low permeability SROP. Mechanical properties and fracture growth predictions provided by BP indicate that water injection at pressures exceeding the Sag River Formation fracture gradient will not cause fracturing through confining intervals into

other permeable strata. Upper confinement for the SROP is provided by the Kingak Formation, an impermeable, Jurassic-aged shale that is approximately 1000 feet thick within the proposed injection area. Lower confinement is provided by the Shublik Formation, a 150 to 200 foot-thick interval of Triassic-aged siltstone, shaley phosphatic limestone and shale. Stratigraphically, there is 1,000 feet of confining shale above the SROP and below the KROP. Additionally there is 2,000 feet of shale overlying the KROP.

A fracture gradient of about 0.7 psi/ft has been measured from fracture stimulations within the Sag River Formation. The fracture gradient of the overlaying Kingak is about 0.72 psi/ft and that of the underlying Shublik is about 0.9 psi/ft based on formation integrity tests. At an injection rate of 3000 BPD, the maximum estimated fracture half-length is less than 300 feet. If it is assumed no stress contrast exists between the Sag River Formation and the overlying Kingak, the maximum fracture growth upward from the perforations will be less than 300 feet, much less than the thickness of the Kingak. Fracture growth downward will not occur with the higher fracture gradient of the Shublik in comparison with the Sag River.

13. Water Analysis (20 AAC 25.402(c)(12)): No water analysis has been performed for the SROP. Water has been produced in well E-13, but it is believed to have been caused via an intersecting fault from underlying Sadlerochit Formation.

14. Aquifer Exemption (20 AAC 25.402(c)(13)): Aquifer Exemption Order 2 (AEO-2) was issued by the Commission on July 8, 1987, and it covered Class II injection activities within the following lands:

    T13N, R9E, UM - Sections 13, 14, 23 and 24

    T13N, R10E, UM – All sections

    T13N, R11E, UM – Sections 5, 6, 7, 8, 15, 16, 17, 18, 19, 20, 21, 22, 29, 30, 31 and 32

    a) On March 28, 2002, BP requested expansion of the AEO-2 to include leases that are wholly or partially included in the MPU. The order expanding Aquifer Exemption Order No. 2 is being considered separately.

15. Hydrocarbon Recovery (20 AAC 25.402(c)(14)): BP plans to proceed with water injection into one fault block pattern to test secondary recovery potential. The estimated original oil in place ("OOIP") in the block ranges from 4.0 to 7.4 MMSTBO. The spread in OOIP is due to uncertainties in porosity/permeability relationship for derivation of net pay cutoff, with the lower value derived from core data gathered in wells MPU C-01, L-01, and B-01. The higher value includes data gathered in Sag River Formation conventional core from the Prudhoe Bay Unit. The cumulative recovery from wells in the block totals 0.4 MSTB. The reservoir pressure measured in MPF-33A during October of 2001 was 3169 psi, suggesting that the OOIP in this block is greater than the 4.0 MMSTBO derived from the MPU core information. BP estimates primary recovery of 15-18 percent of OOIP and waterflood recovery of up to 45 percent OOIP. Application of waterflood within this

fault block is estimated to increase recovery by over 0.9 MMSTB.

a) Reservoir Information from CO 423 (February 25, 1998) provide the following reservoir information:

- Crude Oil Properties: Sag River crude oil properties are 39.2 degrees API, solution GOR of 974 scf/stb, FVF of 1.56 RB/STB, viscosity of 0.277 centipoise, gas gravity of 0.8 and bubble point pressure of 3513 psi.
- Initial Reservoir Conditions: Initial reservoir pressure of 4425 psi and reservoir temperature of 235 degrees F at 8750 feet subsea datum.
- Initial OOIP: Estimates of OOIP provided by BP in support of CO 423 for the SROP of MPU are about 62 million barrels ("MMSTB"). BP is currently re-evaluating the OOIP for the SROP in MPU. The drilling in the F pad area has not significantly changed the structural interpretation; however, uncertainties in the net pay cutoff to be applied exist as indicated earlier. The oil is compartmentalized with approximately 9.7 MMSTB in the F pad area, 49.1 MMSTB in the central area (E and C Pads) and 2.9 MMSTB in the southeast (K Pad Area).

b) Review of Production Information: Production began in the SROP in 1995. Cumulative production to January 21, 2002 is 1.3 MMSTB. Problems with ESP artificial lift and high decline rates have made the SROP development problematic. Wells E-13A and K-33 have been shut in since 1998 with 367 MSTB and 93 MSTB produced, respectively. C-23 has produced 368 MSTB, with a long term shut in from 1998 to 2000. F-33 produced 314 MSTB to early 1999. F-33 was redrilled (F-33A) into the SROP as a horizontal sidetrack with coiled tubing in 2001, and has produced 167 MSTB to date with a current average rate of approximately 600 BOPD. F-73A was drilled in 2001, pre-produced 13 MBO before being shut in awaiting water injection to support F-33A. The use of jet pumps for artificial lift has been shown in F-33A to be more reliable, eliminating costly workovers. Horizontal completions have shown lower decline rate. BP plans to test potential of injection of water to determine if further development within the SROP can be economically pursued. Immiscible and miscible gas injection may also be evaluated.

16. Mechanical Condition of Adjacent Wells (20 AAC 25.402(c)(15)). MPF-33A is the only current offset producer that penetrates the Sag River Oil Pool within ¼ mile radius of the proposed injector. The mechanical integrity of MPF-33A has been reviewed and no problems exist.

17. Incorporation of AIO 10-A findings: The findings of fact in AIO 10, 10A and amendments thereto are incorporated herein to the extent not inconsistent with this order.

18. Discussion of Conservation Order Requirements: CO 423, dated May 6, 1998, requires that a Reservoir Surveillance report after one year of regular production. These reports have not been received by the Commission. Specifically, Rule 12 states: "A surveillance report will be required after one year of regular production and annually thereafter. The report shall include but is not limited to the following: a)

Progress of enhanced recovery project implementation and reservoir management summary including engineering and geotechnical parameters; b) Voidage balance by month of produced fluids and injected fluids and cumulative status; c) Analysis of reservoir pressure surveys within the pool; d) Results and where appropriate, analysis of production and injection log surveys, tracer surveys and observation well surveys; e) Review of pool allocation factors over the prior year; f) Future development plans."

CONCLUSIONS:

1. The application requirements of 20 AAC 25.402 have been met.
2. An area injection order is appropriate for the proposed water injection project for the SROP project under 20 AAC 25.460.
3. Information formerly provided in this application and within CO 423 shows that water injection, lean gas injection, or water alternating gas will significantly improve recovery.
4. Insufficient information has been provided as to the appropriate mix of NGLs with lean gas for MI injection into the SROP. It is anticipated that the MI available at F Pad, which is mixed for the KROP miscibility conditions, will be overly rich for the SROP. However, injection of the MI on a limited basis within F-73A may be appropriate for evaluation purposes.
5. The testing program for injection into the F-33A/F-73A pattern will determine if any fluid compatibility problems exist.
6. BP expects that injection of enhanced recovery fluids at pressures above fracture gradient is required in order to provide sufficient pressure support. Injection in enhanced recovery injection wells in the SROP in the MPU will not involve injection in, or movement of fluids into, the Shallow Sands strata aquifer described in the AEO 2 application and supplemental materials. Injected fluids will be confined within the appropriate receiving intervals by impermeable lithology, cement isolation of the wellbore and appropriate operating conditions.
7. The proposed water injection into the SROP is anticipated to improve recovery.
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. The MPU SROP injection wells are designed to comply with the mechanical integrity requirements specified in 20 AAC 25.412.
10. The findings and conclusions in AIO 10, AIO 10-A, and administrative amendment AIO 10-A.001 are incorporated herein to the extent not inconsistent with this order.
11. The Commission must be apprised on a yearly basis of the performance of the injection project and EOR process evaluation. The Operator shall supply surveillance and development plan information in accordance with applicable pool rules.

NOW, THEREFORE, IT IS ORDERED:

This order supersedes Area Injection Order No. 10-A and previous revisions. The following rules, in addition to statewide requirements under 20 AAC 25 (to the extent not superseded by these rules), govern enhanced oil recovery injection operations in the following area. This area corresponds to the leases held by the Milne Point Unit as of the effective date of this order.

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Township	**Range**	**Sections**
T12N	R10E	1-2 (all); 11-12 (all)
T12N	R11E	1-12 (all)
T13N	R9E	1 (all); 2 (N ½, SE ¼); 11 (NE ¼); 12-14 (all); 23-24 (all)
T13N	R10E	1-36 (all)
T13N	R11E	7-8 (all); 17-20 (all); 27-34 (all)
T14N	R9E	11-15 (all); 22-27 (all); 34-36 (all)
T14N	R10E	15-22 (all); 27-35 (all)

<u>Rule 1 Authorized Injection Stratum for Enhanced Recovery and Authorized Injection Fluids</u>

Subject to the conditions and limitations set out below, enhanced recovery operations as described in the operator's currently effective applications are approved for the KROP, SBOP and the SROP within the above defined area. Authorized injection stratum and authorized injection fluids are set out below for KROP (Part A), SBOP (Part B), and SROP (Part C).

<u>PART A – Kuparuk River Oil Pool</u>

1. <u>Kuparuk River Oil Pool - Authorized Injection Stratum:</u>
   Authorized fluids may be injected into the stratum that correlates with the interval between the measured depths of 6,474 feet and 6,880 feet in the ARCO Alaska, Inc. West Sak River State Well No. 1.

2. <u>Kuparuk River Oil Pool - Authorized Injection Fluids:</u>
   Fluids authorized for injection for the KROP:
   a) produced water and gas from MPU production for purposes of pressure maintenance and enhanced recovery;
   b) source water from the Prince Creek Formation;
   c) seawater to thermally fracture gas injection wells;
   d) tracer survey fluid to monitor reservoir performance;

e) fluids injected for the purposes of stimulation per 20 AAC 24.280(2),
f) miscible gas injectant (including NGLs imported from the Prudhoe Bay Unit) for purposes of pressure maintenance and enhanced recovery), and;
g) non-hazardous treated wastewater from the Milne Point Wastewater Treatment Plant and non-hazardous water collected from MPU reserve pits, well house cellars and standing ponds.

<u>PART B – Schrader Bluff Oil Pool</u>

1. <u>Schrader Bluff Oil Pool Authorized Injection Stratum:</u>
   Authorized fluids may be injected into the stratum that correlates with the interval between the measured depths of 4,174 feet and 4,800 feet in the Conoco MPU Well No. A-1.

2. <u>Schrader Bluff Oil Pool Authorized fluids:</u>
   Fluids authorized for injection for the SBOP are:
   a) produced water from MPU production for purposes of pressure maintenance and enhanced recovery;
   b) source water from the Prince Creek Formation;
   c) tracer survey fluid to monitor reservoir performance
   d) fluids injected for the purposes of stimulation per 20AAC24.280(2) ; and
   e) non-hazardous treated wastewater from the Milne Point Wastewater Treatment Plant and non-hazardous water collected from MPU reserve pits well house cellars and standing ponds.

<u>PART C – Sag River Oil Pool Discussion</u>

1. <u>Sag River Oil Pool - Authorized Injection Stratum:</u>
   Authorized fluids may be injected into the stratum that correlate with the interval between the measured depths of 8810 and 8884 feet within MPU A-01.

2. <u>Sag River Oil Pool - Authorized Injection Fluids:</u>
   Fluids authorized for injection for the KROP are:
   a) produced water and gas from MPU production for purposes of pressure maintenance and enhanced recovery;
   b) source water from the Prince Creek Formation;
   c) seawater to thermally fracture gas injection wells;
   d) tracer survey fluid to monitor reservoir performance;
   e) fluids injected for the purposes of stimulation per 20 AAC 24.280(2) and;
   f) non-hazardous treated wastewater from the Milne Point

Wastewater Treatment Plant and non-hazardous water collected from MPU reserve pits well house cellars and standing ponds. Authorization to continue injection of these fluids is subject to a report on December 31, 2003 confirming fluid compatibility with SROP.

3. Sag River Oil Pool – Temporary Approval for Miscible Gas Injection: To test the applicability of Miscible Gas Injection into the SROP, miscible gas injectant (including NGLs imported from the Prudhoe Bay Unit) may be injected into MPF-73A through December 31, 2003. Administrative approval for continuing this injection beyond this date must be made by application from the Operator with sufficient information to warrant continuation of injection.

Rule 2 Fluid Injection Wells

The underground injection of fluids must be 1) through a well permitted for drilling as a service well for injection in conformance with 20 AAC 25.005; 2) through a well approved for conversion to a service well for injection in conformance with 20 AAC 25.280; or 3) through a well that existed as a service well for injection purposes on the effective date of AIO 10 (September 19, 1986).

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 confirm continued mechanical integrity.

Rule 4 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 5 Notification of Well Integrity Failure

Whenever injection rates and/or operating pressure observations or pressure tests indicate pressure communication or leakage of any casing, tubing or packer, the operator must immediately shut in and secure the well, notify the Commission on the first working day following the observation, and submit a plan of corrective action on Form 10-403 for Commission approval. Additionally, notification requirements of any other State or Federal agency remain the operators' responsibility.

Rule 6 Notification of Improper Class II Injection

Injection of fluids other than those listed in Rule 1, above, 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 comply 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 stratum.

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 dated 23rd day of April 2002.

Cammy Oechsli Taylor, Chair
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).