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

Re: The APPLICATION OF ARCO ALASKA, Inc. ("ARCO") for an order allowing an Enhanced oil recovery project in the Alpine Oil Pool, Colville River field, North Slope Alaska.	)))))	Area Injection Order No. 18 Colville River Field Colville River Unit Alpine Oil Pool January 24, 2000

IT APPEARING THAT:

1. By application dated September 3, 1999, ARCO Alaska, Inc. ("ARCO") requested authorization from the Alaska Oil and Gas Conservation Commission ("Commission") to inject fluids on an area basis for the purposes of enhanced oil recovery from the Alpine Oil Pool. Additional information necessary to complete ARCO's application was submitted on September 13, 1999.

2. ARCO responded to additional questions and met with Commission staff on October 14, 1999 to discuss the Alpine Area Injection Order application.

3. Notice of opportunity for public hearing was published in the Anchorage Daily News on September 16, 1999.

4. A public hearing was held on October 19, 1999.

FINDINGS:

1. Commission regulation 20 AAC 25.460 provides authority to issue an order governing underground injection of fluids on an area basis for all wells within the same field, facility site, reservoir, project, or similar area.

2. The Alpine Oil Pool ("AOP") is located in the Colville River Delta area on Alaska's North Slope.

3. ARCO is the only operator of all wells within one-quarter mile of the area proposed for enhanced oil recovery. The State of Alaska and Kuukpik Corporation are the surface owners.

4. ARCO anticipates drilling approximately 112 development wells on 135 acre spacing to develop 429 million barrels of oil ("MMBO"). The estimated original oil in place ("OOIP") in the Alpine Oil Pool is 960 million barrels of oil.

5. Minimum values of formation water salinity in the Colville Delta Area, determined using standard openhole wellbore geophysical methods calibrated to water samples collected from drill stem and production testing, range from 15,000 to 18,000 milligrams per liter ("mg/l") total dissolved solids ("TDS").

6. The Alpine Oil Pool is contained within the Alpine Sandstone, an Upper Jurassic aged, informal member of the Kingak Formation. It is the stratigraphically highest sandstone within the Kingak Formation in the Colville Delta area. The interval is approximately 7000 feet below sea level and net sand thickness ranges from 30 to 110 feet.

7. The Alpine Sandstone consists of very fine to fine-grained, moderate to well sorted, burrowed, quartzose sandstone with variable glauconite and clay content. Core porosity and permeability ranges are, respectively, from 15% to 23% and 1 to 160 millidarcies. Core area approximate average permeability ranges from 10-15 millidarcies and in the peripheral area 3-6 millidarcies.

8. Approximately 120 feet of ductile shale in the Miluveach Formation overlie the Alpine Sandstone. Core and log analyses indicate the parting pressure of the Miluveach shale is 600 to 700 pounds per square inch ("psi") greater than the Alpine Sandstone.

9. The Alpine Sandstone is underlain by approximately 150 feet of Upper Kingak Formation shales. Petrophysical analysis indicates the parting pressure of the Kingak Formation shales is 700 to 800 psi greater than the Alpine sandstone.

10. Bottom-hole injection pressures are expected to exceed the Alpine formation parting pressure during normal operations. Rock mechanics and fracture analysis indicate that competent confining strata above and below the Alpine Sandstone will confine injected fluids within the Alpine formation.

11. Alpine Pool crude oil gravity is 40 degree API, solution gas-oil ratio is 850 scf/stb, bubble point is 2454 psig, and viscosity is .46 centipoise. Initial reservoir pressure is 3175 psig at 6864 feet TVDss (reference Conservation Order 443) and average reservoir temperature is 160 degrees F.

12. The Alpine crude oil properties create favorable reservoir water–oil mobility ratio that enhances areal and vertical waterflood sweep efficiency. Core flood studies showed residual oil saturation may be expected to range from 35-40% of the OOIP after a waterflood.

13. Estimated high residual water saturation after waterflood provided incentive to study the feasibility of a tertiary enhanced recovery process.

14. The miscible water–alternating–gas ("MWAG") project ARCO proposes is designed to start concurrent with initial pool production to avoid relative permeability related reduction of productivity and injectivity that is expected after water breakthrough. There is potential to prolong production of miscible oil to the extent it may severely impact economics and jeopardize miscible recovery.

15. Results of fine grid compositional reservoir simulations of a MWAG process initiated early in field life indicated ultimate recovery increased up to 10-12% OOIP or approximately 100 million barrels over waterflood.

16. Engineering data indicate productivity and injectivity of wells will be significantly reduced following injection water breakthrough at producing wells. The cause is combined effects of permeability; wettability and changes to relative permeability as alternating injected fluids displace reservoir fluids.

17. Simulations and reservoir properties indicated the strategy to maximize recovery was to place optimal volumes of miscible injectant ("MI") and water into the reservoir prior to injection water breakthrough at the producers.

18. Laboratory experiments have demonstrated the recovery efficiency of MI injection is a function of slug size and diminishes significantly for slug sizes exceeding 30% hydrocarbon pore volume. Optimal slug size is estimated to fall between 20-30%.

19. An equation of state calibrated to slimtube laboratory experiments was used to predict the amount of enriching material to blend with Alpine associated gas to achieve miscibility at a given pressure.

20. Modeling results indicate the proposed depletion plan will maintain the reservoir pressure within the Alpine Oil Pool at or above 3000 psi.

21. The MI slug volume injected will range between 20-30% of hydrocarbon pore volume. The MI will be manufactured from Alpine Pool associated gas and enriching liquids recovered from fuel gas to ensure a minimum miscibility pressure of 2,900 psi.

22. Beaufort Sea water, which has been tested and is compatible with the Alpine formation, will be used for injection initially. Produced water will be injected into the reservoir as it becomes available if it is compatible with the Alpine formation.

23. Produced fluids which are not compatible with the Alpine formation will be disposed in Colville River Unit Well WD-2 as described in Disposal Injection Order No. 18.

24. Production testing of wells in the Alpine Oil Pool has not yielded representative samples of Alpine Sandstone formation water.

25. Maximum MI injection pressures attainable at the plant discharge will be 4,500 psi. Maximum wellhead pressures will vary, and are expected to range from 3,600 to 4,300 psi.

26. Maximum water injection pump discharge pressure is expected to be 2,500 psi. Injection wellhead pressures may vary but are expected to be around 1,800 psi.

27. ARCO will demonstrate the mechanical integrity of injection wells as specified in 20 AAC 25.412 prior to initiating injection operations.

28. The operator will comply with the requirements of 20 AAC 25.402 (d) & (e) to monitor tubing-casing annulus pressures of injection wells periodically during injection operations to ensure there is no leakage and that casing pressure remains less than 70% of minimum yield strength of the casing.

29. All existing wells drilled within the proposed project area have been constructed in accordance with 20 AAC 25.030. All wells abandoned in the proposed project area have been abandoned in accordance with 20 AAC 25.105 or an equivalent precursor regulation.

CONCLUSIONS:

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

2. An Area Injection Order is appropriate for the project area in accordance with 20 AAC 25.460.

3. No underground sources of drinking water (“USDW’s”) exist beneath the permafrost in the Colville River Unit area.

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

5. Enhanced recovery injection fluids will consist of miscible gas and water implemented at startup in order to maximize ultimate recovery.

6. Ample confining shale exists above and below the Alpine Oil Pool to assure containment of the injected fluids within the Alpine formation.

7. The proposed Alpine tertiary enhanced oil recovery project is expected to result in a 10-12 % (approximately 100 million barrels) greater oil recovery than a waterflood project by itself.

8. Well mechanical integrity will be demonstrated in accordance with 20 AAC 25.412 prior to initiation of injection operations.

9. The mechanical integrity of each injection well will be tested at least every four years after an initial test.

10. Tubing-casing annulus pressure and injection rates will be monitored at least weekly for disclosure of possible abnormalities in operational conditions.

11. An Area Injection Order covering the project area will not cause waste nor jeopardize correlative rights and will improve ultimate recovery.

NOW, THEREFORE, IT IS ORDERED THAT Area Injection Order No. 18 is issued with the following rules governing Class II injection operations in the following affected area:

UMIAT MERIDIAN

T11N	R4E	Section 1, 2, 3, 4, 5, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 21, 22, 23, 24, 25, 26, 27.
T11N	R5E	Sections 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, 21, 22, 23, 24, 29, and 30.
T12N	R4E	Sections 24, 25, 26, 27, 33, 34, 35 and 36.
T12N	R5E	Sections 13, 14, 15, 19, 20, 21, 22, 23, 24, 25, 26, 27, 28, 29, 30, 31, 32, 33, 34, 35 and 36.

Rule 1 Authorized Injection Strata for Enhanced Recovery

Within the affected area, fluids may be injected for purposes of pressure maintenance and enhanced recovery into strata that are common to and correlate with the interval between the measured depths of 6876 and 6976 feet in the Bergschrund No. 1 well.

Rule 2 Fluid Injection Wells

The underground injection of fluids must be through a well permitted for drilling as a service well for injection in conformance with 20 AAC 25.005 or through a well approved for conversion to a service well for injection in conformance with 20 AAC 25.280.

Rule 3 Monitoring the Tubing-Casing Annulus Pressure Variations

The tubing-casing annulus pressure and injection rate of each injection well must be checked at least weekly to ensure there is no leakage and that it does not exceed a pressure that will subject the casing to a hoop stress greater than 70% of the casing's minimum yield strength.

Rule 4 Reporting the Tubing-Casing Annulus Pressure Variations

Tubing-casing annulus pressure variations between consecutive observations need not be reported to the Commission unless well integrity failure is indicated as in Rule 6 below.

Rule 5 Demonstration of Tubing-Casing Annulus Mechanical Integrity

A schedule must be developed and coordinated with the Commission that ensures that the tubing-casing annulus for each injection well is pressure tested prior to initiating injection and at least once every four years thereafter. A test surface pressure of 1500 psi or 0.25 psi/ft. multiplied by the vertical depth of the packer, whichever is greater, will be used. The test pressure must show a stabilizing trend and must not decline more than 10% in a thirty-minute period. The Commission must be notified at least twenty-four (24) hours in advance to enable a representative to witness pressure tests.

Rule 6 Well Integrity Failure

Whenever operating pressure observations, injection rates, or pressure tests indicate pressure communication or leakage of any casing, tubing or packer, the operator must notify the Commission on the first working day following the observation, obtain Commission approval of a plan for corrective action, and obtain Commission approval to continue injection.

Rule 7 Plugging and Abandonment of Injection Wells

An injection well located within the affected area must not be plugged or abandoned unless approved by the Commission in accordance with 20 AAC 25.105.

Rule 8 Alpine Oil Pool Annual Reservoir Report

An annual Alpine Oil Pool surveillance report will be required by April 1 of each year subsequent to commencement of enhanced oil recovery operations. The report shall include, but is not limited to, the following:

a. Progress of the enhanced recovery project and reservoir management summary including engineering and geological parameters.
b. Reservoir voidage balance by month of produced and injected fluids.
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 data or surveys.
e. Results of any special monitoring.
f. Reservoir surveillance plans for the next year.
g. Future development plans.
h. Review of Annual Plan of Operations and Development.

Rule 9 Administrative Action

Upon request, the Commission may administratively amend any rule stated above as long as the operator demonstrates to the Commission's satisfaction that sound engineering practices are maintained and the amendment will not result in an increased risk of fluid movement into a USDW.

DONE at Anchorage, Alaska and dated January 24, 1999.

Robert N. Christenson, P.E., Chairman
Alaska Oil and Gas Conservation Commission

Camillé Oechsli Taylor, 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).