FACT SHEET

Proposed Issuance of Underground Injection Control (UIC) Area Permit AK-1I003-A for the Construction and Operation of Class I Non-Hazardous Industrial Waste Injection Wells at the Alpine Oil and Gas Development of the Colville River Unit on the North Slope of Alaska

U.S. Environmental Protection Agency, Region 10
Ground Water Protection Unit, OW-137
1200 Sixth Avenue
Seattle, Washington 98101

December 18, 1998

Introduction

ARCO Alaska, Inc. has submitted an Underground Injection Control (UIC) permit application for the construction and operation of up to three Class I non-hazardous industrial waste injection wells at the Alpine Field in the Colville River Unit on the North Slope of Alaska. The application was submitted to EPA on September 3, 1997, and additional information was sent to EPA on August 4, 1998. In response, EPA has prepared a draft permit for public review and comment. The public comment period will remain open until January 19, 1999, as described later in this fact sheet.

The 10-year term EPA permit would allow ARCO to inject all of the non-hazardous waste fluids generated at the Alpine Field into the naturally saline Ivishak and Sag River Formations at depths of about 8500 to 9500 feet below the land surface. This plan to inject non-hazardous waste fluids generated at Alpine is favored by EPA since it will minimize discharge to the land surface and surface water bodies, and will reduce the need to transport waste from this isolated field (located about 25 miles west of the Prudhoe Bay all-weather road network) to off-site treatment or disposal.

Public Comment

Peer review comments were sought from the Alaska Department of Environmental Conservation (ADEC) and the Alaska Oil and Gas Conservation Commission (AOGCC) in the development of the draft permit and this fact sheet. EPA is now requesting public comment prior to issuing the permit. Persons wishing to comment on the draft permit may do so in writing by January 19, 1999. All comments should include the name, address, and telephone number of the person making comment, a concise statement of the exact basis of any comment, and the relevant facts upon which it is based. All written comments and requests should be submitted to EPA at the above address to the Manager of the Ground Water Protection Unit or via electronic mail to partee.grover@epa.gov . After January 19, 1999, EPA may finalize the permit as drafted if no substantive comments are received during the public notice period.

Regulatory Framework

The Underground Injection Control (UIC) program is authorized by Part C of the Safe Drinking Water Act for the principal purpose of protecting Underground Sources of Drinking Water (USDWs) from contamination by injection through wells. The UIC regulations (see 40 CFR 144.3) broadly define USDWs as any aquifer capable of supplying a public water system with water of less than 10,000 milligrams per liter (mg/L) total dissolved solids (TDS).

Primary responsibility for regulation of injection wells through the UIC program is split in Alaska between EPA and the Alaska Oil and Gas Conservation Commission (AOGCC). The AOGCC has UIC program primacy for the regulation of Class II wells, and EPA directly regulates the other four classes of injection wells in Alaska. Class II wells are defined (see 40 CFR 144.6) as those wells used for injection in order to: 1) dispose of fluids brought to the surface from oil and gas production operations, 2) enhance the recovery of oil or natural gas, or 3) store liquid hydrocarbons

underground. Class I non-hazardous industrial waste wells may be used to inject fluids eligible for Class II injection and any other non-hazardous waste. Therefore, ARCO is seeking to obtain a Class I non-hazardous waste injection well permit from EPA in order to inject all non-hazardous waste fluids generated at the site, regardless of whether or not the wastes are brought to the surface as part of the oil production process.

Underground injection needs to be conducted in a manner which ensures the protection of USDWs. However, based upon available information, EPA has determined that there are most likely not any aquifers beneath the permafrost in the Alpine field area which are fresh enough (less than 10,000 mg/L TDS) to qualify for protection as USDWs. Under these circumstances, the Director may authorize injection with less stringent requirements than would otherwise be required (see 40 CFR 144.16). EPA intends to grant several waivers requested by ARCO which are described under the Geologic Setting and Injection Issues portion of this fact sheet.

General Project Overview

The Alpine field area of the Colville River Unit is located about 60 miles west of Deadhorse, Alaska, and about 25 miles west of the westernmost part of the Prudhoe Bay all-weather road network. The isolated oil development will not be served by an all-weather road. ARCO has requested an area permit to allow the drilling, construction, and operation of up to three Class I non-hazardous industrial waste injection wells from the main facilities pad.

ARCO anticipates that the project will have a lifetime of 20 years. During this time, the Class I injection well(s) may be used to dispose of all non-hazardous waste generated at the project site. ARCO estimates that most of the fluid waste stream will be produced water generated after the field has been producing for about five years. Throughout the project life, the injection well(s) will be used to dispose of camp sewage and grey water, waste fluids intrinsically associated with oil and gas exploration and production, and a variety of non-hazardous industrial waste fluids generated onsite.

A general breakdown of the volumes to be injected over a 20-year period, as estimated by ARCO, are shown below:

Type of Waste	Approximate Volume
Produced Water (maximum case)	14,000,000 barrels
Well completion and workover fluids and solids, rig wash water, drilling mud, well flush water, process facility wastes, etc.	3,250,000
Camp sewage and other domestic wastewater	1,700,000
Non-hazardous industrial waste	50,000
TOTAL	19,000,000 barrels

Most of the waste to be injected will already be in liquid form and thus not require any slurrying or other type of special handling. Wastes which will require some slurrying include frac sand, vessel sludge, line pigging materials, pipe scale, incinerator ash, contaminated gravel, and (if necessary) drill cuttings. ARCO intends to dispose of most drill cuttings either through annular injection as part of the well construction process or through a dedicated Class II injection well, and both of those practices are regulated under permit by AOGCC. However, the Class I injection well to be permitted by EPA could also be used to dispose of drill cuttings if needed.

ARCO has not applied for a hazardous waste injection well permit. Therefore, any listed hazardous wastes will need to be collected, stored, and transported to a RCRA-permitted hazardous waste treatment or disposal facility. Those wastes which are hazardous only because of a characteristic (such as ignitability, corrosivity, toxicity, etc.) may be treated to remove that characteristic and then injected as a Class I non-hazardous waste fluid. The permit does not allow injection of radioactive wastes, as defined in the UIC regulations. Naturally occurring radioactive material (NORM) from sludge or pipe scale (a mineral precipitate formed during production) may be injected.

Geologic Setting and Injection Issues

The geologic setting at the Alpine field area is favorable for fluid waste disposal via injection wells. The stratigraphic sequence and lithology are correlative with the formations found at Prudhoe Bay, where Class II injection wells have operated successfully for almost two decades.

The proposed permit would allow injection into the Ivishak and Sag River Formations of Permian/Triassic age. The Ivishak Formation, which is the lower of the two, contains several porous (about 15%) and permeable (about 30 millidarcies) sandstone intervals which ARCO expects to encounter between about 8900 and 9600 feet below the land surface in the first disposal well. The uppermost sandstone of the Ivishak Formation is separated from the Sag River Formation by about 150 feet of shale and siltstone within the Ivishak, and roughly 300 feet of Shublik Formation limestone. The Sag River Formation is projected to be encountered at 8500 feet below the land surface. In the offsetting Nechelik well, the Sag River Formation is an approximately 50-foot thick interval of porous (about 19%) and permeable (about 120 millidarcies) sandstone.

ARCO estimates that the waste plume, if injected into a single well completed only in the Ivishak Formation, will extend radially around that wellbore almost 3400 feet. If both the Sag River and Ivishak are utilized, the waste plume is likely to extend radially about 2800 feet. Pressure effects from the proposed injection will extend beyond the fluid waste plume itself. Assuming that both the Ivishak and Sag River are utilized for injection, the reservoir pressure is anticipated to rise about 150 pounds per square inch (psi) at the wellbore, just under 100 psi a mile away, and just under 50 psi at a distance of seven miles. Given an original pressure of 4300 psi, these increases above background would be about 3.5%, 2.3%, and 1.2% respectively. These pressure increases are not expected to compromise the integrity of the overlying shale and siltstone confining zone.

The Sag River Formation, which would be the uppermost permitted injection interval, is separated from the overlying Nechelik tight oil zone and the Alpine field oil-producing horizon by about 900 feet of Jurassic age lower Kingak Formation shale and about 300 feet of Jurassic age upper Kingak Formation siltstone. The Kingak Formation will serve as the arresting and confining zone. Above the oil-producing stratigraphic horizon at Alpine lie more than 5000 feet of Cretaceous shale and siltstone, and about 800 feet of permafrost.

The strata at Alpine are almost horizontal, dipping about 1 to 2 degrees to the southwest, and are unfaulted above the proposed injection interval. Northwest-trending normal faults, which are interpreted to have as much as 50 feet of displacement within the Ivishak Formation, die out in the thick shale section of the lower Kingak Formation. Available evidence suggests that the faults do not naturally act as fluid conduits. Any preferential fluid movement along the faults which might occur during injection would likely be restricted to the Ivishak Formation itself.

Both the Ivishak and Sag River injection intervals are naturally saline. ARCO reports that water samples taken from flow tests were measured to have about 23,000 mg/L of TDS, or more than twice the 10,000 mg/L regulatory threshold used to define a USDW. Generally speaking, formation water salinity increases with depth, and so ARCO has used available information to estimate the quality of ground water found in aquifers above the injection intervals and below the permafrost.

Since no water samples have been taken above the oil-producing zone, these ground water quality estimates are based upon the analysis of geophysical borehole logs. These logs are records of the natural gamma radiation, density, and electrical conductivity of the rock and formation water measured before the borehole was cased. Review of these logs show that there are few clean (free from clay minerals or coal) sandstones within the stratigraphic section between the oil-producing horizon and base of the permafrost. Borehole log analysis of these few intervals suggests that they have formation water above the 10,000 mg/L TDS level which defines a USDW, and most of these few clean sandstones have formation water with an estimated TDS concentration of about 20,000 mg/L.

ARCO submitted information to support an aquifer exemption request in the event that EPA were to determine that some aquifers beneath the permafrost are fresh enough to qualify for protection as USDWs. This aquifer exemption request points out that ground water beneath the permafrost is not utilized as a drinking water supply anywhere on the North Slope, estimates the expense of extracting and treating the brackish to saline ground water for use as drinking water, and documents the availability of abundant fresh surface water resources which can be inexpensively treated for use as drinking water. In response, EPA has reviewed the geophysical borehole logs, ARCO's log analysis, the opinion of an AOGCC geologist with expertise in log analysis, and concluded that the available information suggests the few aquifers found beneath the permafrost at Alpine are too naturally saline to qualify as USDWs.

Since the proposed well(s) will not inject below a USDW, EPA may allow less stringent requirements for area of review, construction, mechanical integrity, operation, monitoring, and reporting than would otherwise be required by the UIC regulations (see 40 CFR 144.16). At the Alpine field, EPA intends to only relax some of the operating and monitoring requirements, as described below.

<u>Compatibility of Formation and Injectant</u>: Based upon the applicability of past injectibility studies and injection practices at Prudhoe Bay and other North Slope fields, EPA intends to waive the requirements of 40 CFR 146.12(e) and 146.14(a) which require sampling and characterization of formation fluids and matrix in order to determine whether or not they are compatible with the proposed injectant.

<u>Injection Zone Fracturing</u>: Class I injection wells are prohibited from injecting at pressures which would initiate new fractures or propagate existing fractures within the injection zone. The draft permit instead allows hydraulic fracturing within the injection zone so long as new fractures are not initiated nor existing ones propagated within the upper confining zone.

Injection will be limited to the Ivishak and Sag River Formations. The uppermost injection interval (Sag River Formation) is about 8500 feet beneath the land surface, and approximately 1000 feet below the oil-producing horizon. The strata between the Sag River and the overlying oil-producing stratum is composed mostly of practically impermeable shale and siltstone.

<u>Ambient Monitoring Above the Confining Zone</u>: EPA intends to waive the requirement to monitor the strata overlying the confining zone for fluid movement (see 40 CFR 146.134). The principal purpose of this requirement is to protect overlying USDWs, which are not present at Alpine.

Summary of Proposed Action and Permit Conditions

EPA has primary enforcement authority in Alaska for Class I injection wells as they are regulated by the UIC program, which is authorized by Part C of the Safe Drinking Water Act. EPA grants Class I injection well permits are granted to ensure that waste fluids are safely injected for disposal beneath any existing USDWs, and remain below the confining zone. EPA proposes to grant a permit to ARCO for up to three Class I non-hazardous waste injection wells at the Alpine field, located in the Colville River delta on the North Slope of Alaska. EPA has considered all of the available disposal options, and concludes that underground injection is the most appropriate way to dispose of non-hazardous fluid waste generated at the Alpine field.

Based upon available information, EPA has determined that there are no USDWs beneath the Alpine field area. Considering the absence of USDWs, EPA proposes to grant ARCO a waiver of the UIC program regulation which prohibits hydraulic fracturing of the injection zone during operation (40 CFR 146.13). This waiver is necessary to enable the injection of fluid wastes which contain a small fraction of solid material, and is authorized by the UIC program regulations under 40 CFR 144.16a.

The draft permit contains general legal provisions common to all EPA UIC program permits, specific technical requirements which apply to all Class I injection wells, and particular technical requirements for the proposed injection operation. EPA contacts for further information are Grover Partee at (206) 553-6697 or Jonathan Williams at (206) 553-1369.

Responses to Comments

1. Since the permit was originally applied for in September of 1997, the oilfield under development has become known as the Colville River Field, superceding the unofficial name of the Alpine Field. We request that all reference to the Alpine Field in the permit and fact sheet be changed to the Colville River Field, Colville River Unit.

RESP: Agreed. The appropriate changes will be made in the permit. The Fact Sheet will not be altered.

2. Page 10: (Part I.F.b & Part I.G) ARCO is required to provide financial assurance/responsibility to comply with the requirements 40 CFR 144. It is not clear when this documentation must be initially submitted to EPA. Please clarify when EPA expects ARCO to submit the required demonstration.

RESP: Adequate initial financial assurance was included with the application. Subsequent submittals must be annual and begin not more than one year after the permit effective date. This allows the permittee the flexibility to respond to the requirements of 40 CFR 144 coincident with other annual reporting requirements (e.g., annual SEC filings.)

3. Page 12: (Part II.C.1.b. & Part II.C.3.b.(1)) AAI requests the pressure decline limit of not more than 5% in a thirty minute period be changed to not more than 10% in a thirty minute period. This is consistent with the requirements of the AOGCC.

RESP: We have discussed this with AOGCC and will use the following wording in II.C.1.b.:

> *"In order to demonstrate there is no significant leak in the casing, tubing or packer, the tubing/casing annulus must be pressure tested to at least 3,500 pounds per square inch gauge (psig) for not less than thirty minutes. Pressure shall show a stabilzing tendency. That is, the pressure may not decline more than 10 percent during the test period and shall experience less than one-third of its total loss in the last half of the test period. If the total loss exceeds 5% or if the loss during the second 15 minute period is equal to or greater than one half the loss during the first 15 minutes, the permitee may extend the test period for an additional 30 minutes to demonstrate stabilization."*

II.C.3.b.(1) shall be revised to read as follows:

> *"To detect leaks in the casing, tubing, or packer, the casing-tubing annulus must be pressure tested to at least 3,500 psig for thirty minutes. Pressure shall show a stabilzing tendency as described in II.C.1.b, above. This pressure test is required at a time interval of no more than 12 months between tests."*

4. Page 12: (Part II.C.2) AAI would like to clarify our interpretation of this condition. We intend to have personnel on duty 24 hours per day at the Alpine Production Facility, of which the Class I well and injection plant are a part. Operating personnel will have responsibility for operations of all equipment, including the Class I well. AAI will not have an individual operator assigned solely to the Class I well and disposal facilities on a 24-hour per day basis. We believe our plan of having trained operators on location 24 hours per day at the Alpine Production Facilities meets the requirements of Part II.C.2.

RESP: We agree.

5. Page 12: (Part II.C.3.b.(2)) AAI requests EPA to include language in this condition to allow for equivalent, alternative testing procedures (surveys, logs, etc.) if approved by EPA. Including this language is consistent with 40 CFR 146.68 and provides for permit flexibility in the event federal regulations change or technology enhancements lead to improved test methods. AAI requests the

condition be worded to meet the intent of 146.68 allowing for different test procedures as approved by EPA. AAI suggests the condition read as follows:

"To detect movement of fluids in vertical channels adjacent to the well bore and to determine that the confining zone is not fractured, a radioactive tracer survey, temperature, noise or other approved log shall be run consistent with the requirements of 40 CFR 146.68(d). The tracer tests shall be run at an injection pressure at least equal to the maximum continuous injection pressure observed in the previous six months and the tracer concentration shall be sufficient to ensure detection behind the casing. Copies of all logs shall be accompanied by a descriptive and interpretive report. These fluid movement tests shall be performed as prescribed by 40 CFR 146.68(d) and shall be initiated within 12 months after the first six months of normal operation."

RESP: The draft permit requirements were deemed appropriate for the proposed operation. The regulations at 40 CFR 146.68 apply to wells where normal injection pressures are limited to below the formation parting pressure. The permittee may, of course, utilize tests in addition to those required. The permitee may, moreover, on the basis of the results of such additional tests, request a modification of the permit. The permittee may also request modification to reflect any regulatory flexibility granted in the future (e.g., additional test methods approved.) Also, on advice of AOGCC, the required minimum shut in prior to running the temperature log as specifid in II.C.3.b.(2) will be reduced from three days to two. In order to maximize future flexibility for both ARCO and EPA, however, Part II.C.3.b.(2) shall be rewritten as follows:

> ***In order to detect movement of fluids behind the casing, approved fluid movement tests shall be conducted not less often than annually. Approvable fluid movement tests include, but are not limited to tracer surveys, temperature, noise or other logs. The specific suite of fluid movement tests proposed to satisfy this requirement are subject to prior approval by EPA. Tracer surveys shall be run at injection pressures at least equal to the maximum continuous injection pressure observed in the well in the previous 6 months and the tracer concentration shall be sufficient to ensure detection behind the casing. Copies of all logs shall be accompanied by a descriptive and interpretative report. The initial operational fluid movement tests shall be completed not less than three nor more than nine months after initiation of operation. In the event these initial tests are held after less than six months of operation, tracer surveys shall be run at injection pressures at least equal to the maximum continuous injection pressure observed in the well since the beginning of operation.***

In addition, Part II.C.3.c.(2), which requires notification of EPA 30 days prior to conducting an MIT, will include the following:

> ***Such notice must include an indication of the suite of fluid movement tests the permittee proposes to use. In the event that any of the proposed tests has not been previously approved by the Director, this notice shall include: (a) a complete description of such proposed tests, (b) available evidence supporting the applicability of the proposed test, and (c) a description of such back-up procedures as the permittee deems necessary to adequately demonstrate mechanical integrity in the event that the proposed tests fail to do so.***

6. Page 12: (Part II.C.3.b.(2)) AAI understands that EPA intends the fluid movement tests to begin annually after an initial six month period of normal operations. That is to say that within 12 months after the initial six months of normal operations, we are required to perform appropriate fluid movement tests. It is important to us to be able to schedule these tests when we have access to the necessary equipment and since Alpine is not connected by gravel roads, we may be limited to performing these tests during certain times of the year. If we are required to perform the fluid movement test six months after initiation of injection, it could fall during the summer months when access to existing North Slope infrastructure is not available. This would make performing these tests a very difficult and costly proposal.

RESP: The initial fluid movement test shall be required not less than three nor more than nine *months after initiation of injection.*

7. Page 13: (Part II.C3.c.(5)) In the event the well fails a mechanical integrity test, AAI requests an alternative that is less disruptive to normal operations than the immediate shutting in of the well. We request a condition that would require EPA be consulted within 24 hours of the failure to review the situation and to determine if the well should be shut in.

RESP: This is not acceptable. In the event that the well fails an MIT, a second MIT may be run to verify failure prior to initiating well repairs. However, continued operation of a well which has failed an MIT is not permissible. The well would need to remain shut in until MI can be demonstated. In the event that MI cannot be re-established, the permit as written allows the permittee to drill an additional well or wells to replaced the failed well.

8. Page 13: (Part II.D.7) AAI requests the authorized positive surface pressure be increased to 1500 psig to allow for temperature related pressure swings in a sealed annulus.

RESP: The final permit will limit the surface pressure to 1500 psig.

9. Page 14: (Part II.D.2) The Alpine Class I wells will not use an annular glycol recirculation system. As such, it is not appropriate to monitor the volume of glycol in the annulus between the tubing and the long string casing. Please delete the wording ", and to monitor the volume of glycol in the annulus between the tubing and long string casing" from this condition.

RESP: Initially, EPA proposed that the word "glycol" be replaced by "non-freezing annular fluid." This change would allow the permittee to use glycol, diesel, treated brine or any other appropriate fluid. Monitoring of the annular fluid, whatever it may be, is appropriate and will continue to be required.

Subsequently, ARCO clarified the concern. The proposed system will have a closed annulus and the fluid will not circulate. Appropriate monitoring will be of pressure, not volume. EPA therefore proposes the following changes in Parts II.D.2 and II.D.3: The phrases "monitor the volume of the non-freezing fluid" and "changes in annular fluid volume" will be replaced by "monitor the pressure of the non-freezing fluid" and "changes in annular fluid pressure." Part II.D.3.b will be changed to read as follows:

> *Significant deviations in the annular fluid pressure may indicate losses of mechanical integrity. The permittee shall install and maintain an emergency shutdown system to respond to such deviations.*

10. Page 14: (Part II.D.3.a) Consistent with our previous comment, please delete the wording "and significant changes in annular fluid volume" as it refers to a system that AAI will not have in place on the Alpine Class I wells.
RESP: See #9, above

11. Page 14: (Part II.D.3.b) Consistent with our previous comment, please delete this entire condition as it refers to a system that AAI will not have in place on the Alpine Class I wells.
RESP: See #9, above

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 10
1200 Sixth Avenue
Seattle, Washington 98101

February 3, 1999

Reply To The
Attn.. Of: OW-137

Michael A. Stahl
Sr. Permit Coordinator
Environmental Permiting, Prudhoe Bay
ARCO Alaska, Inc.
P O Box 100360
Anchorage, AK 99510-0360

Re: Class I Injection Well Permit
Alpine Development Project
AK-1I003-A

Dear Mr. Stahl:

Enclosed is the final US Environmental Protection Agency Class I Underground Injection Control (UIC) Program permit for the planned Class I non-hazardous industrial waste injection well at the Alpine Production Facility, Colville River Field, Colville River Unit. Copies of the Fact Sheet, Public Notice and Response to Comments are also enclosed.

Comments were received during the public comment period only from ARCO and AOGCC. The permit as proposed takes effect on this date and will remain in effect for ten (10) years, until February 3, 2009.

As you requested, the permit allows some flexibility regarding mechanical integrity test procedures. In our experience, a combination of a radioactive tracer survey (RTS) and a shut-in temperature log is adequate and is approvable. Any proposed substitute tests, alone or in combination, require prior approval. Please request such approval at the earliest stage but in no case later than 30 days prior to the test date. Our experience with the borax log, which you have proposed in discussions with Jonathan Williams, has not been good. We are willing to again consider such tests, but strongly recommend you have some back-up procedures ready to go in the event that the borax log results are inconclusive. Note that operation of the well in the absence of a clear demonstration of mechanical integrity is specifically prohibited by the permit.

At this point, our expectation is that external mechanical integrity tests will include both a radioactive tracer survey and shut-in temperature log. However, we understand that scheduling a two-day shut-down prior to running a temperature log would present some logistical difficulties this coming summer and fall. As you have indicated, ARCO expects to have a full construction camp generating large volumes of domestic waste. And there will be no ice road available to temporarily haul domestic waste off site in the event that the temporary wastewater storage capacity were exceeded. Therefore, we do not expect ARCO to shut-in the injection well for the first operational MIT, which the permit requires between 3 and 9 months after the initial MIT and well start-up. Instead, our expectation is that the this MIT would include a tracer survey and the use of whatever temperature logging tool that would give the most useful information without an extended pre-test shut-in. ARCO can then conduct the next test at its convenience next winter when an ice road is operating and continue on an annual schedule of winter-time MITs.

We appreciate your cooperation during the processing of the permit. If you have any questions, please call Grover Partee at (206) 553–6697 or Jonathan Williams at (206) 553–1369.

Sincerely,

Randall F. Smith
Director
Office of Water

cc: David Johnson, AOGCC
Brad Fristoe, ADEC