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

Re: **THE APPLICATION OF CONOCOPHILLIPS ALASKA, INC.** for an amendment to the order authorizing underground injection of fluids for enhanced oil recovery in the Meltwater Oil Pool, in the Meltwater Participating Area, Kuparuk River Field, North Slope, Alaska	)	**Area Injection Order No. 21B** Docket No. AIO-15-015 Kuparuk River Field Kuparuk River Unit Meltwater Oil Pool October 8, 2015

IT APPEARING THAT:

1. Area Injection Order (AIO) 21 authorizing underground injection of fluids for enhanced oil recovery was issued for the Kuparuk River Unit (KRU) Meltwater Oil Pool (MOP) on August 1, 2001. Based upon additional information presented by ConocoPhillips Alaska, Inc. (CPAI), AIO 21 was revoked and replaced by AIO 21A on May 16, 2013.

2. Recent geologic and production data analyses indicate AIO 21A does not accurately describe the MOP and confinement of injected fluids.

3. By application received on April 14, 2015 CPAI, as operator of the KRU, requested four amendments to existing rules of AIO 21A.

4. A notice of a public hearing was published on the State of Alaska Online Public Notice web site and on the Alaska Oil and Gas Conservation Commission (AOGCC) web site on May 4, 2015. On May 5, 2015, the notice was published in the Alaska Dispatch News. The hearing was scheduled for July 9, 2015.

5. The AOGCC received no comments or requests for a public hearing.

6. On July 9, 2015, the public hearing convened.

7. At the conclusion of the July 9, 2015 hearing, the AOGCC requested additional information from CPAI. The record was left open until July 16, 2015. CPAI submitted the requested information on July 16, 2015.

FINDINGS:

1. The Environmental Protection Agency exempted all aquifers within the existing KRU. 40 CFR 147.102.

2. CO 456A defines the MOP as strata equivalent to those between 6,785 and 6,974 feet measured depth (MD) in well Meltwater North #2A.

3. Regular production from the MOP commenced in November 2001. Miscible gas

injection began in January 2002, and water injection commenced in May 2003. Producing wells initially used miscible injectant (MI) for artificial lift.

4. The initial reservoir pressure for the MOP was approximately 2,400 psi. Injection activity increased reservoir pressure near injection wells to over 4,000 psi; reservoir pressure near shut-in producers reached nearly 3,000 psi.

5. CPAI encountered elevated gas pressures while drilling MOP well KRU 2P-441 in March 2002.

6. Beginning in April 2002, CPAI noted elevated outer annulus pressures in MOP development wells. Gas samples taken from outer annuli had chemical signatures consistent with MI. CPAI initially suspected MI gas used for artificial lift was migrating into the outer annuli, possibly through leaking, threaded casing connections.

7. After identifying elevated outer annulus pressures in MOP wells, CPAI initiated an annulus-monitoring program and attempted periodic annulus pressure bleeds. Since 2003, CPAI has provided periodic updates of monitoring and diagnostic efforts to AOGCC.

8. Water injection into the MOP ceased in October 2009 due to water supply line corrosion concerns. CPAI converted existing MOP water-injection wells to MI injection or shut them in. CPAI no longer uses water injection, other than for short term diagnostic purposes.

9. Using proprietary 4D seismic evaluation, CPAI identified a potential vertical migration mechanism from the MOP that allowed injected fluids to escape from the MOP and enter shallower strata.

10. During April 2012, CPAI reduced the injection-to-withdrawal ratio to ensure confinement of injected fluids to the MOP. Outer annuli pressures subsequently declined. In August 2012, CPAI restricted MI injection pressure to ensure that sand-face injection pressure remains less than 3,400 psi.

11. On October 4, 2012, AOGCC issued Administrative Approval AIO 21.001 allowing continued MI injection into the MOP subject to several conditions, including: daily recording of well pressures, monthly reporting of all MOP wells, and pressure restrictions on the outer annuli of all wells.

12. CPAI requests AOGCC revise AIO 21A to address numerous changes needed because CPAI believes injected gas is now being confined to the MOP as required by AOGCC regulations and AIO 21A.

13. Rule 2 of AIO 21A prohibits new wells and well conversions in the MOP. CPAI requests Rule 2 be modified to allow new wells (grassroots wells), development well sidetracks, and well conversions within the MOP. CPAI requests this change to allow for producer to injector conversions and the ability to drill new development wells and coil tubing sidetracks within the MOP. CPAI believes that by placing injectors and producers within the same lobe deposit, injected fluids will be contained within the MOP, the risk of further migration of injected fluids will be reduced, and ultimate hydrocarbon recovery will be improved.

14. CPAI requests modification of Rule 8 of AIO 21A, to allow injection of Beaufort Sea water and KRU produced water for surveillance, logging near wellbore formation displacements, and well maintenance.

15. CPAI requests modification of Rule 9 of AIO 21A, Performance Reporting, to read "The Operator shall submit an annual synopsis of the surveillance, monitoring, and development initiatives completed during the previous year that pertain to the confinement of injected fluids within the Bermuda Interval together with the Meltwater Annual Surveillance Report."

16. CPAI requests removing Rule 11 of AIO 21A, Expiration Date, which was extended on May 6, 2015 by AIO 21A.007 to November 16, 2015. CPAI states in its application "…surveillance and monitoring data suggest that the implementation of the new reservoir management strategy has prevented further migration of fluids out of the MOP. The existing rules in AIO 21A, together with the aforementioned proposed amendments, will ensure long term confinement of injected fluids and optimal hydrocarbon recovery." CPAI submitted additional information on July 16, 2015 stating "ConocoPhillips believes that a period of 10 years between Area Injection Order renewals is appropriate for AIO 21A. This recommended period of 10 years is predicated upon the cycle time to design and complete development initiatives and to evaluate the field performance data."

CONCLUSIONS:

1. AIO 21A and associated administrative actions should be revoked and replaced with a time-limited injection order tailored to the circumstances in the MOP.

2. Injection activities at the MOP resulted in loss of confinement. Injected fluids migrated into shallower strata, entered uncemented portions of offset wells, and elevated pressures in the outer annuli of numerous MOP wells. Injection well reservoir pressures above 4,000 psi (Finding 4), exceeded the fracture initiation pressure of the Bermuda and confining strata (Finding 18 AIO 21A) establishing migration pathways.

3. CPAI estimates that 25-30 percent of the fluids injected into the MOP cannot be accounted for in the reservoir material balance and are suspected to have escaped reservoir containment. Annulus pressure bleeds cannot account for this full volume of escaped fluid. The possibility that gas charged sands overlying the MOP may exist is a significant drilling hazard. Grassroots wells should be treated like exploratory wells including requiring mud logs, gamma ray logs, porosity and resistivity logs, and a shallow hazards survey to identify potentially gas charged shallow sands.

4. CPAI has implemented reservoir management practices including reducing the injection-to-withdrawal ratio and restricting the MI injection pressure in response to the migration of MI out of the MOP. Indications are that these changes may be allowing migration pathways to close, however, continued measures are required to confirm the effectiveness of these mitigating practices.

5. Water injection for the purpose of surveillance, logging, near wellbore formation

displacements, and well maintenance is a valuable tool to properly develop and manage the MOP. Since Beaufort Sea water was previously authorized by AIO 21A.003 and AIO 21A.005 for a limited time for video and fluid movement logging, this fluid should be authorized.

6. With the dissipating amounts of MI recovered during the annulus bleed operations and other information indicating migration pathways are closing, a monthly report is no longer necessary. A detailed annual report will provide sufficient information for the AOGCC to properly monitor this issue moving forward.

NOW, THEREFORE, IT IS ORDERED THAT AIO 21 and AIO 21A and all associated administrative approvals are hereby revoked and replaced by this order. All information related to AIO 21 and AIO 21A is hereby incorporated by reference into the record for this order. The following rules, in addition to statewide requirements under 20 AAC 25 (to the extent not superseded by these rules), govern Class II enhanced oil recovery injection operations in the affected area described below:

Umiat Meridian

Township	Range	Section
T8N	**R7E**	**Sections 1 through 36: All State Lands**

Rule 1 Authorized Injection Strata for Enhanced Recovery (Source: AIO 21)

Within the affected area, fluids appropriate for enhanced recovery may be injected for purposes of pressure maintenance and enhanced recovery into strata that are common to, and correlate with, the interval between 6,785' and 6,974' MD in well Meltwater North #2A.

Rule 2 Meltwater Oil Pool Wells (Source: – Revised this Order)

For any new well drilling surface hole in the affected area:

a. A well site survey in accordance with 20 AAC 25.061(a) will be required; and

b. Mud logs, gamma ray logs, porosity and resistivity logs will be required from the base of the conductor to total depth.

Rule 3 Monitoring the Tubing-Casing Annulus Pressure Variations (Source: AIO 21, AIO 21.001)

The tubing-casing annulus pressure and injection rate of each injection well must be checked at least weekly to confirm continued mechanical integrity. The operator shall record wellhead pressures and injection rates daily. The operator shall limit the outer annulus pressure to 1000 psi.

Rule 4 Demonstration of Tubing-Casing Annulus Mechanical Integrity (Source: Revised this Order)

The mechanical integrity of an injection well must be demonstrated before injection begins, and before returning a well to service following a workover affecting mechanical integrity. An AOGCC-witnessed mechanical integrity test (MIT) must be performed after injection is commenced for the first time in a well, to be scheduled when injection conditions (temperature, pressure, and rate) have stabilized and every 2 years thereafter. MIT's must be conducted in accordance with AOGCC Industry Guidance Bulletin No. 10-02A – "Mechanical Integrity Testing" and done to a test pressure equal to the maximum anticipated surface injection pressure. The AOGCC must be notified, following the procedures in AOGCC Industry Guidance Bulletin No. 10-01A – "Test Witness Notification", at least 48 hours in advance to enable a representative to witness a MIT. The MIT report (AOGCC Form 10-426) must be provided to AOGCC no later than the 5^{th} calendar day of the month following the testing. Test results must be readily available for AOGCC inspection upon request.

Rule 5 Notification of Improper Class II Injection (Source: Revised this order)

Injection of fluids other than those listed in Rule 8 without prior authorization is improper Class II injection. Upon discovery of such an event, the operator must immediately notify the AOGCC, provide details of the operation, and propose actions to prevent recurrence. Notification to AOGCC does not relieve the operator of the notification requirements of any other State or Federal agency.

Rule 6 Well Integrity and Confinement (Source: AIO 21A)

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 immediately notify the AOGCC and obtain permission for continued operation of the well. A corrective action plan shall be provided for AOGCC review and approval prior to further action being taken. The operator will also consult with the AOGCC about the need to shut in all wells in the MOP.

Rule 7 Authorized Injection Pressure (Source: AIO 21A.004)

Injection pressures must be maintained at or below 3,400 psig at the reservoir sand-face.

Rule 8 Authorized Fluids for Injection (Source: Revised this order)

Fluids authorized for injection are:

a. Miscible injectant;
b. Dry gas provided by the Kuparuk River Unit;
c. Tracer survey fluid to monitor reservoir performance;
d. Fluids injected for stimulation purposes per 20 AAC 25.280(a)(2);
e. Glycol from hydro-tests and freeze protection;
f. Diesel used for freeze protection;

g. Methanol used for freeze protection;
h. Standard oilfield chemicals (corrosion and scale inhibitors, defoamers, emulsion breakers, etc.);
i. Beaufort Sea water used for surveillance, logging, near wellbore formation displacements, and well maintenance; and
j. KRU produced water used for surveillance, logging, near wellbore formation displacements, and well maintenance.

Any other fluids, or uses for the above fluids, shall be approved in advance by separate action based upon proof of compatibility with the reservoir and formation fluids.

Rule 9 Performance Reporting (Source: Revised this order)

The operator shall submit to AOGCC an annual synopsis of the surveillance, monitoring, and development initiatives completed during the previous year that pertain to the confinement of the injected fluids within the MOP together with the Meltwater Annual Surveillance Report. The annual surveillance report will be required by April 1 of each year. 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. assessment of fracture propagation into adjacent confining intervals;
f. summary of MIT results;
g. summary of results of inner and outer annulus monitoring for all production wells, injection wells, and any wells that are not cemented across the Meltwater Oil Pool and are located within a ¼-mile radius of a Meltwater injector;
h. results of any special monitoring;
i. reservoir surveillance plans for the next year; and
j. future development plans.

Rule 10 Administrative Action (Source: AIO 21A)

Upon proper application, or its own motion, and unless notice and public hearing are otherwise required, the AOGCC may administratively waive the requirements of any rule stated herein or administratively amend this order 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.

Rule 11 Expiration Date (Source: Revised this order)

This order shall expire if CPAI ceases to be the Designated Operator for the KRU. If CPAI continues as Designated Operator, this order shall expire five years after the effective date shown below unless prior to the expiration date CPAI requests the order be extended.

Any such request shall include:

a. A review of the existing rules in the order and an analysis whether or not those rules should be retained, amended, or repealed;
b. A review of, and discussion on, whether or not the affected area of the order should be revised; and
c. A discussion of, and justification for, proposed new rules or revisions to existing rules.

Done at Anchorage, Alaska and dated October 8, 2015.

Cathy P. Foerster
Chair, Commissioner

Daniel T. Seamount, Jr.
Commissioner

RECONSIDERATION AND APPEAL NOTICE

As provided in AS 31.05.080(a), within **20** days after written notice of the entry of this order or decision, or such further time as the AOGCC grants for good cause shown, a person affected by it may file with the AOGCC an application for reconsideration of the matter determined by it. If the notice was mailed, then the period of time shall be **23** days. An application for reconsideration must set out the respect in which the order or decision is believed to be erroneous.

The AOGCC shall grant or refuse the application for reconsideration in whole or in part within 10 days after it is filed. Failure to act on it within 10-days is a denial of reconsideration. If the AOGCC denies reconsideration, upon denial, this order or decision and the denial of reconsideration are **FINAL** and may be appealed to superior court. The appeal **MUST** be filed within **33** days after the date on which the AOGCC mails, **OR 30** days if the AOGCC otherwise distributes, the order or decision denying reconsideration, **UNLESS** the denial is by inaction, in which case the appeal **MUST** be filed within **40** days after the date on which the application for reconsideration was filed.

If the AOGCC grants an application for reconsideration, this order or decision does not become final. Rather, the order or decision on reconsideration will be the **FINAL** order or decision of the AOGCC, and it may be appealed to superior court. That appeal **MUST** be filed within **33** days after the date on which the AOGCC mails, **OR 30** days if the AOGCC otherwise distributes, the order or decision on reconsideration. As provided in AS 31.05.080(b), "[t]he questions reviewed on appeal are limited to the questions presented to the AOGCC by the application for reconsideration."

In computing a period of time above, the date of the event or default after which the designated period begins to run is not included in the period; the last day of the period is included, unless it falls on a weekend or state holiday, in which event the period runs until 5:00 p.m. on the next day that does not fall on a weekend or state holiday.