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 order authorizing underground injection of fluids for enhanced recovery in the proposed Moraine Oil Pool within the Kuparuk River Field, Kuparuk River Unit	))))))))	Docket Number: AIO-16-011 Area Injection Order No. 39 Kuparuk River Unit Kuparuk River Field Kuparuk River-Torok Oil Pool North Slope Borough, Alaska July 22, 2016

IT APPEARING THAT:

1. By application received March 31, 2016, ConocoPhillips Alaska, Inc. (CPAI), as operator of the Kuparuk River Unit (KRU) and on behalf of the Working Interest Owners, requested authorization for the injection of fluids for enhanced recovery in the proposed Moraine Oil Pool.

2. Pursuant to 20 AAC 25.540, the Alaska Oil and Gas Conservation Commission (AOGCC) scheduled a public hearing for May 10, 2016. On April 6, 2016, the AOGCC published notice of that hearing on the State of Alaska’s Online Public Notice website and on the AOGCC’s website, electronically transmitted the notice to all persons on the AOGCC’s email distribution list, and mailed printed copies of the notice to all persons on the AOGCC’s mailing distribution list.

3. No comments on the application were received.

4. The hearing commenced at 9:00 a.m. on May 10, 2016. Testimony was received from representatives of CPAI.

5. The record was held open until May 24, 2016, to allow CPAI to respond to requests made during the hearing.

FINDINGS:

1. Pool Definition: Conservation Order No. 725 defines the Kuparuk River-Torok Oil Pool (KRTOP) and establishes pool rules that govern development operations and production.[1]

[1] For naming consistency, to emphasize continuity of the accumulation across lease and unit boundaries, and to conform to the definition of the term “pool” under AS 31.05.170(12) in Conservation Order No. 725, the AOGCC applied the name Kuparuk River-Torok Oil Pool to this pool in lieu of CPAI’s proposed name “Moraine Oil Pool”.

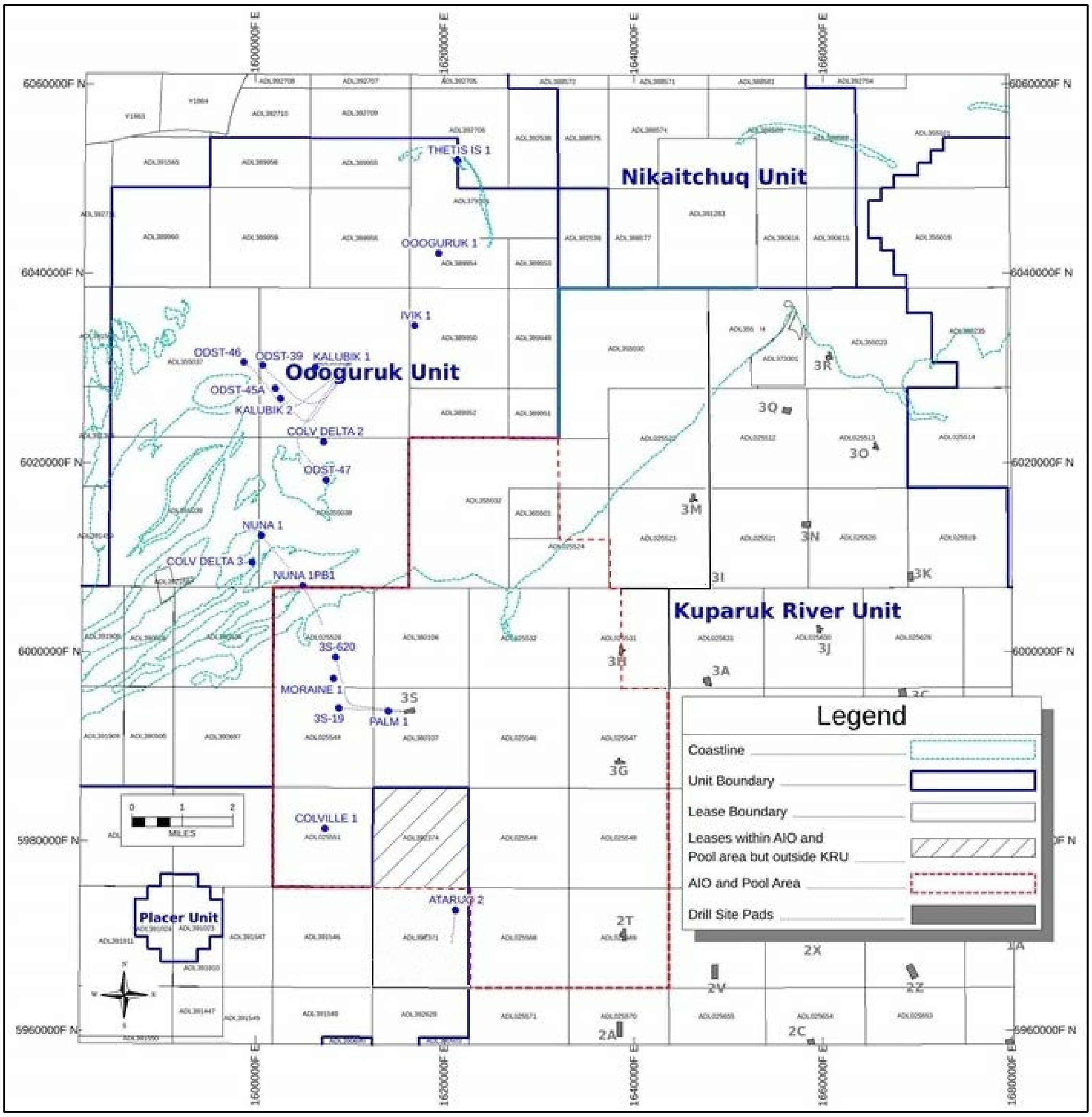

Figure 1. Kuparuk River-Torok Oil Pool Affected Area[2]

2. Owners and Landowners: The State of Alaska is landowner for the planned Affected Area. (See Figure 1). Working interest owners include CPAI, BP Exploration (Alaska) Inc., Chevron USA Inc., and ExxonMobil Alaska Production Inc.

CPAI verified by letter dated May 24, 2016 that the ownership and working interest percentage for oil and gas lease ADL 392374 is in alignment with the ownership and working interest percentage for those KRU oil and gas leases within the pool boundary.

[2] This map is presented for illustration purposes only. It has been modified from an original map submitted by CPAI in support of the Area Injection Order application. For a more precise depiction of the Affected Area, refer to the legal description presented on page 10 of this order.

The royalty interest for ADL 392374 is 16.66667 percent. Royalty interest for the KRU oil and gas leases within the pool ranges from 12.5 to 16.667 percent.

3. Operator: CPAI is the operator of the leases in the proposed Affected Area, which is defined below.

4. Surface Owners: The State, several native allotments overseen by the Bureau of Indian Affairs, and the North Slope Borough are the surface owners within one-quarter mile of the proposed Affected Area.

5. Adjacent Operators: Eni Petroleum US LLC, 70&148, LLC, Caelus Natural Resources Alaska, LLC, ASRC Exploration LLC, and Brooks Range Petroleum Corporation are the operators within one-quarter mile of the proposed effective area.

6. Notification of Surface Owners and Operators: In accordance with 20 AAC 25.402(c)(3), CPAI provided an affidavit with the application showing that copies of the Area Injection Order (AIO) application were sent by certified mail to the surface owners and operators identified in Findings 2, 4 and 5 on March 31, 2016. CPAI provided proof of certified mailing to the AOGCC.

7. Affected Area Proposed for Enhanced Oil Recovery: CPAI requests authorization to inject fluids for the purposes of enhanced recovery operation on lands in the Kuparuk River Unit. The proposed injection area includes portions of Township (T) 11 North, Range (R) 8 East; T12 North, R 7 East; T 12 North, R 8 East; and T 13 North, R 8 East, Umiat Meridian. (See Figure 1).

8. Interval Proposed for Enhanced Oil Recovery: Enhanced recovery injection is proposed within the Kuparuk River-Torok Oil Pool, which is defined in Conservation Order No. 725 as the interval that correlates to 4,991 to 5,272 feet measured depth (MD) on the resistivity log recorded in the Kalubik No. 1 exploration well. (See Figure 2.)

9. Description of Operations: The KRTOP will be developed initially from the existing onshore 3S Drill Site with four to five hydraulically fractured horizontal producers and three to four fracture stimulated horizontal injectors. Wells will be completed with 3,000 to 8,000 foot horizontal sections within the KRTOP. Upon successful development of the initial drilling program from 3S Drill Site, additional wells may be drilled from 3S Drill Site. One to two additional drill sites may be constructed for further development. Wells will trend northwest and will be arranged in a line drive pattern. Water injection with possible future injection of lean (IWAG) or miscible gas (MWAG) will enhance recovery from the KRTOP. Injection operations will be managed to maintain reservoir pressure near the original reservoir pressure.

10. Geology:

a. Stratigraphy:

The KRTOP consists of lower Cretaceous-aged, Brookian, slope-to-basin turbidite deposits comprising thinly laminated mudstones, siltstones and very fine to fine-grained sandstones. Within the proposed development area, the reservoir interval ranges from 140 to more than 200 feet in thickness. Regionally, this reservoir interval thins towards the southeast and southwest, and it pinches out to the west against the paleo-shelf. The sandstone and siltstone beds are interpreted to be locally continuous,

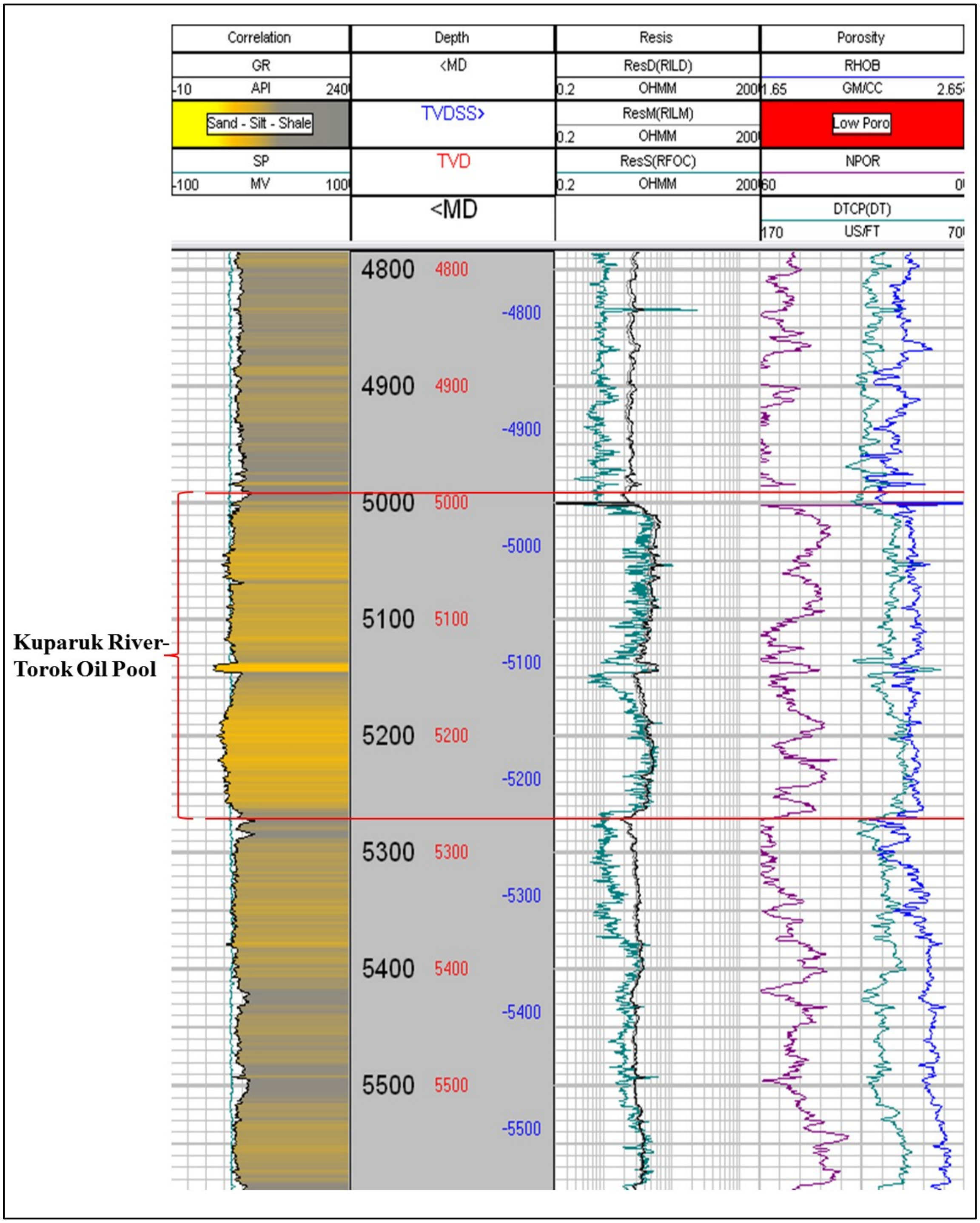

Figure 2. Kalubik No. 1—Type Well Log for the Kuparuk River-Torok Oil Pool[3]

[3] Figure 2 is presented for illustration purposes only. Refer to the well log measurements recorded in exploratory well Kalubik No. 1 for the precise representation of the Kuparuk-Torok Oil Pool.

sheet-like deposits within turbidite lobe complexes. Individual beds range in thickness from less than an inch to a few feet. The sandstones comprise 50 to 70 percent quartz, 1 to10 percent feldspar, and 15 to 30 percent lithic fragments. Porosity values from core data range from 15 to 28 percent and average 19 percent. Air permeability values range from 0.5 to 93 millidarcies and average 5 millidarcies. Water saturation estimates for the reservoir siltstones and sandstones range from 30 to 85 percent.

b. Structure:

The structure of the pool forms a broad, east-plunging anticlinal nose. Two dominant sets of normal faults are present in the proposed development area: an early Cretaceous-aged, west-northwest-trending system and a younger, Cenozoic-aged, north-northeast-striking set. Vertical displacement along these faults may range as much as 60 feet and, due to the thinly bedded nature of the reservoir, faults may act as barriers to flow.

Within the Affected Area, the top of the KRTOP lies between -4,940 and -5,880 feet true vertical depth below mean sea level (also termed true vertical depth subsea and represented herein by the acronym TVDss).[4]

c. Trap Configuration and Seals:

Well log and seismic information indicate that the KRTOP is trapped by both structural and stratigraphic elements. The sandstones that comprise the pool thin toward the west and pinch out as they lap onto the shelf slope. Much of the trap is stratigraphic, with a structural component from the broad anticline. To the south and southwest, the depositional limit of the fan defines the pool boundary. To the east and northeast structural dip and diminishing sand content define the limit of the oil accumulation.

Progradational slope deposits consisting of Torok mudstones and siltstones overlying and underlying the reservoir provide the top and bottom seals. An additional confining zone would be provided by the underlying HRZ Shale.

d. Reservoir Compartmentalization:

At present, extended production test results of both KRU 3S-19 and KRU 3S-620 are consistent with laterally continuous productive sands within the upper Moraine over development well spacing distances of 1,000 to 2,000 feet. Compartmentalization is possible due to faulting and the highly laminated nature of the reservoir. All wells, including injectors, will likely be fracture stimulated to enhance productivity, improve vertical injection sweep, and connect thin, individual sandstone beds.

[4] To avoid confusion, when depths presented represent true vertical depth subsea, the footage will be preceded by a negative sign and followed by the acronym TVDss (e.g., 4,940 feet true vertical subsea will be depicted as -4,940 feet TVDss).

e. Permafrost Base:

The base of the permafrost is interpreted to lie between -500 and -1,700 feet TVDss within the proposed development area.

11. Reservoir Fluid Contacts: Regional Reservoir Description Tool data were used by CPAI to delineate fluid contacts. The water zone contact is controlled by the Ivik 1 exploratory well, which is located within the Oooguruk Unit, and the oil zone contact is controlled by the Moraine 1 well, which is located within the Kuparuk River Unit. According to testimony provided on April 26, 2011 by Pioneer Natural Resources Alaska, Inc. (predecessor to current Oooguruk Unit operator Caelus), the highest known water for the pool is established by MDT (modular formation dynamics tester) measurements in the Ivik 1 exploratory well at -5,212 feet TVDss. CPAI estimates the oil-water contact (OWC) between -5,190 and -5,275 feet TVDss. CPAI testified that there is mobile water present in the Moraine Oil Pool beginning at a depth of -5,190 to -5,275 TVDss. This may take the form of a single OWC, multiple OWCs, or a transition zone of mobile oil and water.

12. Reservoir Fluid Properties (-5,000 feet TVDss Datum):

Initial reservoir pressure	2,263 psig
Reservoir temperature	135^{o} F
Gas-oil ratio	425 scf/bbl
API gravity	26.5^{o} F
Bubble point pressure	2,134 psig
Oil formation volume factor	1.2 rb/stbo
Oil viscosity	2.5 cp
Gas formation volume factor	1.2 bbl/mscf (at saturation pressure)
OWC	estimated between -5,190 and -5,275 feet TVDss

13. In-Place and Recoverable Oil Volumes:

Hydrocarbon Resources	Estimated Volume (MMSTB)	
	Drill Site 3S	Additional Drill Site
Original Oil in Place (OOIP)	100-500	100-300
Primary Recovery (5% OOIP)	5-25	5-15
Primary + Waterflood (10-40% OOIP)	10-200	10-120
Primary + IWAG (11-45% OOIP)	11-225	11-135
Primary + MWAG (13-55% OOIP)	13-275	13-165

Regular production from this pool within the Kuparuk River Unit began in 2013 from KRU 3S-19, and it has been reported in the AOGCC's records as the Kuparuk River Torok Undefined Oil Pool.

14. Well Logs for Injectors: To date no injection wells have been drilled in the KRTOP. When injection wells are drilled, logs will be filed with the AOGCC in accordance with the requirements of 20 AAC 25.

15. Mechanical Integrity and Design of Injection Wells: The proposed well design is similar to that used in the Kuparuk River Oil Pool with production casing set below the base of the West Sak Formation and cemented back to surface. Intermediate casing will be set with the shoe just above or just into the Torok Formation. The intermediate casing will be cemented in accordance with AOGCC regulations to assure proper isolation of any potentially hydrocarbon bearing zones. The wells are likely to be horizontal wells completed with solid liners with pre-perforated pups and/or sliding sleeves and external swell packers. Wells will likely need to be hydraulically fractured and will be completed with 4-1/2" tubing to accommodate this. Due to limitations with wellbore access for fracture stimulation and workover operations that may occur in the planned horizontal wells if the packer is set no more than 200 feet MD above the perforated interval, as required by 20 AAC 25.412(b), CPAI requests a waiver to allow the packer to be set more than 200 feet MD above the top of the perforated interval but the packer would not be located above the confining zone and with a minimum of 300 feet MD of outer casing cement above the packer setting depth. Tubing/casing annular pressure will be tested in accordance with AOGCC regulations and cement bond logs, or other data approved by the AOGCC, shall be run on each injection well to demonstrate isolation of injected fluids to the approved injection interval.

16. Injection Fluids: CPAI proposes initially to inject produced or seawater in the KRTOP to enhance recovery and may follow the water flooding in the future with lean or miscible gas injection to further enhance recovery. CPAI requests authorization to inject the following fluids:

a. Source water from the Kuparuk seawater treatment plan.
b. Produced water from all present and yet-to-be defined oil pools within the Kuparuk River Field, including without limitation the Kuparuk River Oil Pool and the KRTOP.
c. Enriched hydrocarbon gas (MI): Blend of KRU lean gas with indigenous and/or imported natural gas liquids.
d. Lean gas.
e. Fluids used during hydraulic stimulation.
f. Tracer survey fluids to monitor reservoir performance.
g. Fluids used to improve near wellbore injectivity.
h. Fluids used to seal wellbore intervals which negatively impact recovery efficiency.

i. Fluids associated with freeze protection.
j. Standard oilfield chemicals.

17. Fluid Compatibility: The KRTOP has a high clay content, but the majority of the clay occurs in laminar sheets between the reservoir intervals. Dispersed clay within the sandstone layers is not expected to be prone to swelling at the typical injection water salinities. Produced water from the KRTOP indicates the potential for moderate scaling during production and when mixed with seawater. Scaling risk is minimized by the placement of aqueous and solid phase scale inhibitors during the hydraulic fracture treatments, squeeze treatments, and chemical injection at the surface. These methods are expected to control scale risk. No compatibility issues are expected with proposed injection gases.

18. Injection Rates and Pressures: Maximum anticipated injection rates are 6,000 barrels per day or 6 million standard cubic feet per day, actual maximum rates for the wells will be constrained so that injection pressures do not exceed the overburden pressure gradient to prevent fractures from penetrating through the confining layer. The overburden pressure gradient, derived from the Moraine 1 core data, is 0.72 psi/ft. Maximum injection pressure will not exceed 0.67 psi/ft and average injection pressure at the sand face will be 0.62 psi/ft. Injection volumes will be managed to offset production voidage.

19. Fracture Confinement: CPAI built a fracture simulation model based on the Moraine 1 well log data, calibrated to core sample geo-mechanical tests data, and pressure matched to KRU 3S-620 hydraulic fracturing results. The fracture simulation model was used to model hydraulic fracturing operations as well as water injection operations. The model results showed fractures to be contained within the KRTOP and no risk of breaching the confining layers.

20. Formation Water Quality and Aquifer Exemption: Analysis of KRTOP water samples collected from Moraine 1 core measured 21,362 mg/l of total dissolved solids. Calculated salinity for produced water from the KRU 3S-19 and 3S-620 wells ranged from 16,000 to 20,000 mg/l NaCl. Calculated and measured salinity values exceed the 10,000 mg/l cutoff for freshwater. In 40 CFR 147.102(b)(3), the EPA adopted an aquifer exemption that covers the proposed affected area.

21. Offset Wells: Moraine 1 is a properly abandoned, vertical exploratory well that is approximately 725 feet from the proposed KRU 3S-613 injection well. The only other well in the initial development area is the producer KRU 3S-620 well, which is located approximately 1,450 feet from the proposed injector. Future wells drilled in this area will be evaluated in accordance with AOGCC regulations.

22. Waiver: CPAI requests a waiver of the Injection packer setting depth requirement of 20 AAC 25.412(b) for injection wells in the KRTOP to accommodate wellbore access for hydraulic fracturing and workover operations. Injection packers will not be set above the upper confining interval and will be set with outer casing cement extending a minimum of 300 feet MD above the packer.

CONCLUSIONS:

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

2. Operation of an enhanced oil recovery injection project in the Kuparuk River-Torok Oil Pool will significantly improve recovery from the pool.

3. The injection interval does not contain freshwater and is not a potential underground source of drinking water.

4. Review of laboratory data and analogous reservoirs indicates that fluids proposed for injection, when properly treated, will be compatible with the Kuparuk River-Torok Oil Pool formation and formation water. Scale formation will be controlled using standard oilfield practices.

5. The proposed injection activities will be conducted in permeable and hydraulically fractured strata. These strata can be reasonably expected to accept injected fluids at pressures that are lower than those required to fracture through the surrounding confining intervals.

6. Injected fluids will be confined within the receiving interval by thick and laterally impermeable confining layers, cement isolation of the wellbores, and appropriate operating conditions.

7. Regular well surveillance and reservoir monitoring will demonstrate appropriate performance of the enhanced recovery project and disclose possible abnormalities. An annual report of injection performance is required and must include an assessment of fracture propagation into adjacent confining intervals.

8. Setting the packers in the injection wells more than 200 feet MD above the injection interval to facilitate wellbore access for hydraulic fracturing and workover operations will not increase the potential of an injection fluid confinement failure, provided the packer is at least 300 feet MD below the top of the production casing cement and is not above the confining interval. The location of production casing cement will be established through cement bond logging or alternate methods deemed acceptable by the AOGCC. Any alternate methods must be approved in advance by the AOGCC. MITs will ensure integrity of injection wells.

9. Reservoir voidage will be maintained at a replacement ratio of about 1:1.

10. Injection pressure will be limited to a maximum sand face injection pressure gradient of 0.67 psi/ft.

11. Sufficient information has been provided to authorize injection of fluids into the Kuparuk River-Torok Oil Pool for the purposes of pressure maintenance and enhanced oil recovery.

<u>NOW THEREFORE IT IS ORDERED:</u>

The underground injection of fluids for pressure maintenance and enhanced oil recovery is authorized in the following area, subject to the following rules and 20 AAC 25, to the extent not superseded by these rules.

Affected Area: Umiat Meridian

Township 11 North, Range 8 East	Sections 1-4, 9-12: All
Township 12 North, Range 7 East	Sections 1-2: All
	Sections 11-14: All
	Sections 23-26: All
	Sections 35-36: All
Township 12 North, Range 8 East	Sections 2-11, 13-36: All
Township 13 North, Range 8 East	Sections 19-21, 28-34: All

Rule 1 Authorized Injection Strata for Enhanced Recovery

Fluids authorized under Rule 3, below, may be injected for purposes of pressure maintenance and enhanced oil recovery within the Affected Area into strata that are common to, and correlate with, the interval within the Kalubik No. 1 well between 4,991 and 5,272 feet MD on the resistivity log recorded in exploratory well Kalubik No. 1.

Rule 2 Well Construction

To facilitate wellbore access, in lieu of the packer depth requirement under 20 AAC 25.412(b), the packer/isolation equipment depth may be located above 200 feet MD from the top of the perforations/open interval, but shall not be located above the confining zone and shall have outer casing cement volume sufficient to place cement a minimum of 300 feet MD above the planned packer depth.

Rule 3 Authorized Fluids

Fluids authorized for injection are:

a. Source water from the Kuparuk seawater treatment plant.

b. Produced water from all present and yet-to-be defined oil pools within the Kuparuk River Field, including without limitation the Kuparuk River Oil Pool and the Kuparuk River-Torok Oil Pool.

c. Enriched hydrocarbon gas (MI): Blend of KRU lean gas with indigenous and/or imported natural gas liquids.

d. Lean gas.

e. Fluids used during hydraulic stimulation.

f. Tracer survey fluids to monitor reservoir performance.

g. Fluids used to improve near wellbore injectivity.

h. Fluids used to seal wellbore intervals which negatively impact recovery efficiency.

i. Fluids associated with freeze protection.

j. Standard oilfield chemicals.

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 4 Authorized Injection Pressure for Enhanced Recovery

Injection pressures will be managed as to not exceed the maximum injection gradient of 0.67 psi/ft to ensure containment of injected fluids within the Kuparuk River-Torok Oil Pool.

Rule 5 Monitoring Tubing-Casing Annulus Pressure

Inner and outer annulus pressure shall be monitored each day for all injection and production wells. Inner annulus, outer annulus, and tubing pressure shall be constantly monitored and recorded for all injection and production wells. The outer annulus pressures of all wells that are not cemented across the Kuparuk River-Torok Oil Pool and are located within a ¼-mile radius of a Kuparuk River-Torok Oil Pool injector shall be monitored daily. All monitoring results shall be documented and available for AOGCC inspection.

Rule 6 Demonstration of Tubing/Casing Annulus Mechanical Integrity

The mechanical integrity of each injection well must be demonstrated before injection begins and before returning a well to service following any workover affecting mechanical integrity. An AOGCC-witnessed MIT must be performed after injection is commenced for the first time in a well, to be scheduled when injection conditions (temperature, pressure, rate, etc.) have stabilized. Subsequent tests must be performed at least once every four years thereafter. The AOGCC must be notified at least 24 hours in advance to enable a representative to witness an MIT.

Unless an alternate means is approved by the AOGCC, mechanical integrity must be demonstrated by a tubing/casing annulus pressure test using a surface pressure of 1,500 psi or 0.25 psi/ft multiplied by the vertical depth of the packer, whichever is greater, that shows stabilizing pressure and does not change more than 10 percent during a 30-minute period. Results of MITs must be readily available for AOGCC inspection.

Rule 7 Well Integrity and Confinement

Whenever any pressure communication, leakage or lack of injection zone isolation is indicated by an injection rate, operating pressure observation, test, survey, log, or any other evidence (including outer annulus pressure monitoring of all wells within a one-quarter mile radius of where the Kuparuk River-Torok Oil Pool is not cemented), the Operator shall notify the AOGCC by the next business day and submit a plan of corrective action on a Form 10-403 for AOGCC approval. The Operator shall immediately shut in the well if continued operation would be unsafe or would threaten contamination of freshwater. A monthly report of daily tubing and casing annuli pressures and injection rates must be provided to the AOGCC for all injection wells for which well integrity failure or lack of injection zone isolation is indicated.

Rule 8 Annual Performance Reporting

An annual surveillance report will be required by April 1st of each year subsequent to commencement of enhanced oil recovery operations. In addition to such other information as the AOGCC may require, the report shall include 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 Kuparuk River-Torok Oil Pool and are located within a ¼-mile radius of a Kuparuk River-Torok Oil Pool injector;

h. results of any special monitoring;

i. reservoir surveillance plans for the next year; and

j. future development plans.

Rule 9 Notification of Improper Class II Injection

Injection of fluids other than those listed in Rule 3 without prior authorization is considered 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. This requirement is in addition to, and does not relieve the operator of any other obligations under the notification requirements of any other State or Federal agency, regulation or law.

Rule 10 Other Conditions

If fluids are found to be fracturing the confining zone or migrating out of the approved injection stratum, the Operator must immediately shut in the injection wells and immediately notify the AOGCC. Injection may not be restarted unless approved by the AOGCC.

Rule 11 Administrative Action

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 12 Expiration Date

This order shall expire if ConocoPhillips Alaska Inc. ceases to be the Designated Operator for the Kuparuk River Unit or five years after the effective date shown below, whichever occurs first, 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 July 22, 2016.

//signature on file//
Cathy P. Foerster
Chair, Commissioner

//signature on file//
Daniel T. Seamount, Jr.
Commissioner

ALASKA OIL AND GAS CONSERVATION COMMISSION SINCE 1955

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.

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.