ALASKA POLLUTANT DISCHARGE ELIMINATION SYSTEM
PERMIT FACT SHEET – Preliminary Draft
Permit Number: AKG315200
Oil and Gas Exploration, Production and Development in State Waters in Cook Inlet

DEPARTMENT OF ENVIRONMENTAL CONSERVATION
Wastewater Discharge Authorization Program
555 Cordova Street
Anchorage, AK 99501

Public Comment Period Start Date: [insert date]
Public Comment Period Expiration Date: [insert date]
Alaska Online Public Notice System

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Issuance of an Alaska Pollutant Discharge Elimination System (APDES) general permit to:

OIL AND GAS EXPLORATION, DEVELOPMENT AND PRODUCTION

IN STATE WATERS IN COOK INLET

The Alaska Department of Environmental Conservation (Department or DEC) is reissuing APDES general permit AKG315200 – Oil and Gas Exploration, Development and Productions in State Waters in Cook Inlet (Permit). The Permit authorizes and sets conditions on the discharge of pollutants to state waters in Cook Inlet from oil and gas facilities and certain non-oil and activities with similar discharges. In order to ensure protection of water quality and human health, the Permit places limits on the types and amounts of pollutants that can be discharged from these operations and outlines best management practices to which these operations must adhere.

This fact sheet explains the nature of potential discharges from oil and gas exploration facilities operating in state waters in Cook Inlet and the development of the Permit including:

- Information on appeal procedures
- A description of the industry
- A listing of effluent limits, monitoring requirements, and other conditions
- Technical material supporting the conditions in the Permit

Public Comment

Persons wishing to comment on the Draft Permit may do so in writing by the expiration date of the public comment period. In addition, commenters may provide oral comments by attending a public hearing, if scheduled, as well as providing written comments. Written comments should be submitted to the Department at the technical contact address, fax, or email identified above (see also the public comments section of the attached public notice). Mailed comments and requests must be postmarked on or before the expiration date of the public comment period. Commenters are requested to submit a concise statement on the permit condition(s) and the relevant facts upon which the comments are based. Commenters are encouraged to cite specific permit requirements or conditions in their submittals.

The Department will hold a public hearing whenever the Department finds, on the basis of requests, a significant degree of public interest in a Draft Permit. The Department may also hold a public hearing if a hearing might clarify one or more issues involved in a permit decision. A public hearing will be held at the closest practicable location to the site of the operation. If the Department holds a public hearing, the Director will appoint a designee to preside at the hearing. A hearing will be recorded. The public should also submit written testimony in lieu of or in addition to providing oral testimony at the hearing. The Department plans to hold two hearings during the public comment period at the following times and locations:

Anchorage, Alaska

Homer, Alaska

After the close of the public comment period, the Department will review the comments received on the Draft Permit. The Department will respond to both written and oral comments received in a Response to Comments document that will be made available to the public. If no substantive comments are received, the tentative conditions in the Draft Permit will become the proposed Final Permit.

The proposed Final Permit will be made publicly available for a five-day applicant review. After the close of the proposed Final Permit review period, the Department will make a final decision regarding permit issuance. A Final Permit will become effective 30 days after the Department's decision, per the appeals process in Alaska Administrative Code (AAC) 18 AAC 15.185.

The Department will transmit the Final Permit, fact sheet (amended as appropriate), and the Response to Comments to anyone who provided comments during the public comment period or who requested to be notified of the Department's final decision.

Appeals Process

The Department has both an informal review process and a formal administrative appeal process for final APDES permit decisions. An informal review request must be delivered within 20 days after receiving the Department's decision to the Director of Water at the following address:

Director of Water
Alaska Department of Environmental Conservation
410 Willoughby Street, Suite 303
Juneau AK, 99811-1800

Interested persons can review 18 AAC 15.185 for the procedures and substantive requirements regarding a request for an informal Department review. For information regarding informal review of Department decisions see http://www.dec.state.ak.us/commish/InformalReviews.htm. An adjudicatory hearing request must be delivered to the Commissioner of the Department within 30 days of the permit decision or a decision issued under the informal review process. An adjudicatory hearing will be conducted by an administrative law judge in the Office of Administrative Hearings within the

Department of Administration. A written request for an adjudicatory hearing shall be delivered to the Commissioner at the following address:

Commissioner
Alaska Department of Environmental Conservation
410 Willoughby Street, Suite 303
Juneau AK, 99811-1800

Interested persons can review 18 AAC 15.200 for the procedures and substantive requirements regarding a request for an adjudicatory hearing. See http://dec.alaska.gov/commish/review-guidance/adjudicatory-hearing-guidance/ for information regarding appeals of Department decisions.

Documents are Available

The Permit, Fact Sheet, and related documents can be obtained by visiting or contacting DEC between 8:00 a.m. and 4:30 p.m. Monday through Friday at the addresses below. The Permit, Fact Sheet, and other information are also located on the Department's Wastewater Discharge Authorization Program website: http://dec.alaska.gov/water/wastewater/.

Alaska Department of Environmental Conservation
Division of Water
Wastewater Discharge Authorization Program
555 Cordova Street
Anchorage, AK 99501
(907) 269-6285

Alaska Department of Environmental Conservation
Division of Water
Wastewater Discharge Authorization Program
410 Willoughby Avenue, Suite 310
Juneau, AK 99801
(907) 465-5180

Alaska Department of Environmental Conservation
Division of Water
Wastewater Discharge Authorization Program
610 University Avenue
Fairbanks, AK 99709-3643
(907) 451-2183

Alaska Department of Environmental Conservation
Division of Water
Wastewater Discharge Authorization Program
43335 Kalifornsky Beach Rd. - Suite 11
Soldotna, AK 99669
(907) 262-5210

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1.0 INTRODUCTION

1.1 General Permits

Section 301(a) of the Clean Water Act (CWA) and Alaska Administrative Code (AAC) Chapter 18, Section 83.015 (18 AAC 83.015) provide that the discharge of pollutants is unlawful except in accordance with an Alaska Pollutant Discharge Elimination System (APDES) permit. Often the discharge of pollutants is regulated by the Alaska Department of Environmental Conservation (DEC or Department) through an individual APDES permit. However, 18 AAC 83.205 allows the issuance of an APDES general permit to categories of discharges when a number of point sources are:

- Located within the same geographic area and warrant similar pollution control measures;
- Involve the same or substantially similar types of operations;
- Discharge the same types of wastes;
- Require the same effluent limits or operating conditions;
- Require the same or similar monitoring requirements; and
- In the opinion of the Department, are more appropriately controlled under a general permit than under individual permits.

1.2 Legal Basis Overview

18 AAC 83.210(a) allows a general permit to be administered according to the individual permit regulations found in 18 AAC 83.115 and 18 AAC 83.120. Like an individual permit, a violation of a condition contained in a general permit constitutes a violation of the CWA and subjects the permittee of the facility with the permitted discharge to the penalties specified in Alaska Statute (AS) 46.03.020(12). In accordance with 18 AAC 83.155, general permit AKG315200 –Oil and Gas Exploration, Development and Production in State Waters in Cook Inlet (Permit) will remain in force and effect via administrative extension should the e Department be unable to reissue the permit prior to its expiration date.

1.3 Individual Permits

A permittee authorized to discharge under a general permit may request to be excluded from coverage by applying for an individual permit. This request must be made by submitting APDES permit application Form 1, Form 2C, and Form 2M (if applicable) with supporting documentation to DEC.

The Department may require any person authorized by a general permit to apply for and obtain an individual permit, or any interested person may petition the Department to take this action. Per 18 AAC 83.215. The Department may consider the issuance of an individual permit when: the discharger is not in compliance with conditions of the general permit a change has occurred in technology or practices; effluent limits guidelines (ELGs) are promulgated; a water quality management plan is approved; circumstance have changed so that the discharger is no longer appropriately controlled under the general permit or the authorized discharge must be either temporarily or permanently reduced; DEC determines that the discharge is significant contributor of pollutants.

2.0 BACKGROUND

2.1 Cook Inlet Oil and Gas History and Industry Description

Cook Inlet region is a mature petroleum province, with exploration activities first occurring in the late 1800s. Sporadic exploratory drilling occurred near natural oil seeps in the early 1900s. The end of World War II brought increased settlement to the Kenai Peninsula and the development of a road system, and the improved access led to an increase in exploration. Oil and gas-related activities in Cook Inlet began nearly 70 years ago with initial exploration discoveries in the late 1950s. In 1955, Richfield Oil Corporation discovered oil in the Swanson River area, and this discovery spurred the drilling of additional wells and increased leasing activity on both sides of Cook Inlet. Both oil and gas fields have been steadily developed since then. Discoveries in the Cook Inlet Basin extend from the Kachemak Bay area north to the mouth of the Susitna River and include offshore and onshore fields from the western shore of the Cook Inlet to the western and southern Kenai Peninsula (DNR 2014 Annual Report). Oil exploration activities peaked around 1967 with additional discoveries in the early 1990s. Oil and gas infrastructure in the Cook Inlet area is well developed relative to other areas of the state. The following paragraph provides an overview of some of this infrastructure that is critical to discussions in this fact sheet but is not intended to provide a holistic overview.

There are many offshore and onshore oil and gas production facilities operating in Cook Inlet, which are operated by Hilcorp Alaska, LLC (HAK), Cook Inlet Energy, LLC (CIE), and Furie Operating Alaska, LLC (Furie). Cook Inlet has several onshore oil processing facilities, including Trading Bay Production Facility (TBPF), Middle Ground Shoal (MGS) Onshore, Granite Point Tank Farm (GPTF), Kustatan Processing Facility (KPF), Furie Gas Production Facility (Furie GPF), and the Cosmopolitan Production Facility (CPF). There is also an oil refinery (formerly Tesoro) and a liquefied natural gas (LNG) facility (Formerly ConocoPhillips Alaska Inc.) in Nikiski both going through ownership transfer to the parent company Andeavor. Connecting these upstream and midstream oil and gas facilities is a network of approximately 250 miles of undersea pipelines, 80 miles of oil pipelines and 170 miles of gas pipelines, operated by Harvest Alaska LLC (Harvest), Cook Inlet Pipeline Company (CIPL), and Kenai Pipeline (KPL). An important project being conducted by Harvest, a subsidiary of HAK, will eliminate Drift River Terminal that has historically received crude oil via pipeline from production facilities on the west side of Cook Inlet and stores it until transported via tankers across Cook Inlet to the refinery. The Harvest pipeline project will create a connection to this existing network to facilitate transfer of oil from TBPF and GPTF to the refinery via subsea pipelines and eliminate transporting oil via tanker from Drift River. The subsequent decommissioning of the Drift River Terminal, located at the base of the active volcano Mount Redoubt, and eliminating oil tankers in Cook Inlet is seen as a large reduction in environmental risk for the Cook Inlet oil and gas industry.

Oil production at the Cosmopolitan Unit by BlueCrest Energy and gas production at the Kitchen Lights Unit by Furie are examples of two recently successful exploration and development projects in Cook Inlet. CIE has plans to conduct exploration at their Sabre site located state waters near Trading Bay. CIE is also proposing to upgrade the treatment and disposal systems at KPF to include discharges of produced water. By discharging produced water instead of injecting it and over-pressurizing reservoirs, CIE can optimize enhanced oil recovery (EOR) and projects extending the operation of their current fields by 10 to 15 years. Since acquiring assets in Cook Inlet beginning in 2012, HAK has invested in upgrades to existing facilities, which resulted in a 25 percent (%) increase in oil production by June 2014 at approximately 15,800 barrels per day. As for Cook Inlet gas, reserves in 1970 were approximately 8 trillion cubic feet (tcf) and oil

production peaked at approximately 230,000 barrels per day in 1970 and had been in steady decline since, although recent production rates in the last few years have been increasing. Over time, gas has been consumed at approximately 145 billion cubic feet per year, with 8.3 tcf produced. Projections in 2010 suggested that these gas reserves might be exhausted by 2013, and this spurred increased exploration for gas in Cook Inlet. The present supply-demand condition for Cook Inlet gas presents a renewed incentive for exploration and development. New gas exploration and development projects are underway and other projects are anticipated in the near future. A recent estimate of existing reserves is 1.184 tcf of gas (DOG, 2015). According to a 2011 USGS report, an estimated technically recoverable 599 million barrels of oil and 19 tcf of gas in the Cook Inlet basin remains undiscovered (USGS 2011).

2.2 Regulatory History of Oil and Gas in Cook Inlet

2.2.1 The 1986 Cook Inlet General Permit

For operators required to have a permit, the Environmental Protection Agency (EPA) issued individual NPDES permits from 1972 until 1986, when EPA issued the first general permit AKG-28-5000 - Oil and Gas Exploration, Development, and Production Facilities in Cook Inlet (1986 GP). The 1986 GP set limitations for domestic wastewater to comply with minimum treatment standards per 18 AAC 72; minimum treatment is defined as meeting secondary treatment. Essentially, secondary treatment is defined by meeting maximum daily limits (MDLs) of 60 milligrams per liter (mg/L) for both five-day biochemical oxygen demand (BOD_5) and total suspended solids (TSS) and 30 mg/L as an average monthly limit (AML) for these same parameters.

Approximately 10 separate discharges were lumped together under limitations for no discharge of free oil and described as miscellaneous discharges. The 1986 GP established a prohibition of discharging within 1,000 meters of biologically sensitive areas such as an Area Meriting Special Attention (AMSA) per requirements from Alaska Coastal Management Program (ACMP). Any exploration mobile offshore drilling unit (MODU) discharging within 1,500 meters of a biologically sensitive area was required to conduct Environmental Monitoring Program (EMP) Studies on the fate and effects of drilling fluids and drill cuttings. Existing production facilities discharging produced water shoreward of the 10 meter isobaths were required to submit information within one year of the effective date to support verification of existing mixing zones. New production facilities seeking coverage to discharge produced water in upper Cook Inlet could apply by submitting information necessary for conducting a mixing zone evaluation at least six months prior to discharge for authorizing a mixing zone.

2.2.2 The 1999 Cook Inlet General Permit

In 1996, EPA promulgated ELGs for oil and gas extraction per Title 40 of the Code of Federal Part 435 (40 CFR 435). Implementing these newly promulgated requirements, EPA reissued the 1986 GP in 1999 (1999 GP). During reissuance, DEC and EPA evaluated the domestic wastewater limits established in the 1986 GP based on data collected from various treatment system operating from 1992 to 1994. The determination was that only systems with biological treatment serving platforms continuously manned by 10 or more staff could attain secondary standards. This understanding resulted in less stringent limits for other facilities based on the type of treatment system and level of staffing, while the limits from the 1986 GP were retained for systems with biological treatment and continuous staffing. In addition, limits for total residual chlorine were established with an MDL of 19 mg/L and an AML of 9 mg/L.

Similar to the 1986 GP, the 1999 GP established no free oil limitations for miscellaneous discharges. However, the 1999 GP also required submittal of annual chemical inventory for the discharges of noncontact cooling water, waterflooding, and desalination waste streams. The

1999 GP also continued the prohibition of discharges within 1,000 meters from biologically sensitive areas and expanded the EMP study requirements to 4,000 meters of AMSAs and other sensitive nearshore locations. The primary objective of these EMP studies was to inform future decisions about expanding the area of prohibition from 1,000 to 4,000 meters. Lastly, the 1999 GP established two sets of interim limits based on flow rates over or under one million gallons per day (mgd) for new produced water discharges that could apply for coverage after the effective date of the 1986 GP. The permittee was also required to submit mixing zone application using the first year of data obtained while discharging 18 months after initiating discharges.

2.2.3 The Existing 2007 Cook Inlet General Permit

2.2.3.1 Limitations in Existing 2007 Cook Inlet General Permit

In 2007, EPA reissued the Cook Inlet general permit under a new permit number designation and title, AKG-31-5000 – Oil and Gas Extraction Facilities in Federal and State Waters in Cook Inlet (2007 GP). This reissuance included some significant changes from previously issued Cook Inlet GPs.

For domestic wastewater discharges, the 2007 GP retained the limits based on secondary standards but eliminated the MDL for total residual chlorine (TRC) and modified the AMLs to become facility specific or fixed platforms. The result of developing specific AMLs for TRC was four facility were lower and five facilities had limits greater than 9 mg/L. For exploration MODUs that could discharge anywhere in the coverage area, a maximum TRC limit of 1 mg/L and a standard-sized 100 meter mixing zone were imposed.

For miscellaneous discharges, the 2007 GP retained no discharge of free oil and the chemical inventory but established both standard-sized and facility specific mixing zones and added chronic whole effluent toxicity (WET) testing requirements including chronic toxicity triggers. WET monitoring for miscellaneous discharges was only required when the daily discharge is greater than 10,000 gallons per day (gpd) and chemical additives are used. For existing facilities in coastal waters and any new facilities in federal waters, mixing zones were established to ensure water quality criteria is met at the boundary of a chronic mixing zone while characterization of these discharges could be quantified using chronic WET monitoring. The triggers were included to accelerate testing and reporting requirements. New facilities operating in coastal waters, including exploration MODUs, were authorized a standardized 100 meter mixing zone and conducted WET monitoring for the purpose of characterization without triggers. For existing fixed platforms operating in coastal waters, chronic WET triggers were based on acute toxicity estimates derived from chemical additive safety data sheets (SDS). Those acute estimates were applied as chronic toxicity triggers for fixed platforms to be compared to chronic WET tests results measured in chronic toxicity units (TU_c). If the trigger was exceeded, accelerated testing was required. The intended approach for characterizing miscellaneous discharges was hindered due to WET testing dilution series permit requirements to include two dilutions above and two dilutions below the chronic toxicity triggers instead of bracketing toxicity endpoints from previous WET tests (See Section 2.3.2).

Because no EMP Studies had been conducted during the term of the 1999 GP, the 2007 GP required that all new exploration MODUs conduct EMP studies regardless of location. In addition, although no EMP data was available to support the decision, the 1,000 meter prohibition was increased to 4,000 meters. Justification for this decision included better protection of critical habitat for Steller sea lions, the possibility that extended-reach directional drilling could be used to explore nearshore locations, alternative disposal methods could be used in lieu of discharging, or an individual permit could be issued.

2.2.3.2 Environmental Studies Conducted Under the Existing 2007 Cook Inlet General Permit

The 2007 GP required a comprehensive sampling study to gather data regarding potential impacts to the receiving water and the fate and transport of discharged parameters of concern (POCs) associated with produced water (Produced Water Study). The study included samples collected in 2008 and 2009 in conjunction with the Integrated Cook Inlet Monitoring and Assessment Program (ICIEMAP) that provide a baseline for water quality and sediment hydrocarbon and metal concentrations. Partners in the ICIEMAP study included the National Oceanic and Atmospheric Administration (NOAA), the Cook Inlet Regional Citizens Advisory Council (CIRCAC), and DEC. DEC administers the EPA Environmental Monitoring and Assessment Program (EMAP) in Alaska, and CIRCAC provided scientific support for data collection and reporting for Cook Inlet studies. The overall statistical design of the ICIEMAP study followed EMAP protocol. The program provided more site-specific information on water quality, sediment quality, and physical and biological parameters for Cook Inlet than was available previously. The Final Produced Water Report issued July 10, 2010 expanded upon research efforts by other stakeholders evaluating environmental effects of oil and gas activities in Cook Inlet and has been used extensively during reissuance of the Permit.

2.2.3.3 Subsequent Legal Challenges to the Existing 2007 Cook Inlet General Permit

The CWA Section 401 Certification of Reasonable Assurance (CWA 401 Certification) issued by DEC for the 2007 GPt included an antidegradation analysis per 18 AAC 70.015. The 2007 GP was subject to a challenge in the United States (US) Court of Appeals for the Ninth Circuit (Ninth Circuit), and the disposition was filed October 21, 2010 [See Cook Inlet keeper et al, petitioners v. US EPA, No. 07-72420]. The Ninth Circuit granted an EPA motion for voluntary partial remand of the Permit, subject to certain reporting requirements. Among those requirements, the Ninth Circuit required EPA to report on the Department's progress to develop the guidance document *Interim Antidegradation Implementation Methods*, dated July 14, 2010 (*Interim Methods*) for implementing the Antidegradation Policy under 18 AAC 70.015. The Department developed and finalized interim methods on July 14, 2010. EPA reviewed the *Interim Methods* and found them to be consistent with Alaska state policy and the CWA.

In 2011, effluent limits from the 2007 GP for produce water discharges were re-proposed by EPA, which was accompanied by a CWA 401 Certification developed by the Department. On November 21, 2011 a Request for Adjudicatory Hearing was submitted to the Commissioner of DEC for judgment as to whether the *Interim Methods* qualified as regulation that required public comment. The Commissioner, due to pending litigation regarding the *Interim Methods* in the Alaska Superior Court (Court), stayed this request. On February 23, 2012 a petition for review was submitted to the Ninth Circuit using a similar basis as the hearing request [See Cook Inlet Keeper et al, petitioners v. US EPA, No. 12-70572]. On September 4, 2012 the Court found the *Interim Methods* did not qualify as regulations requiring public notice. After the appeal period for the court's decision expired, the Commissioner lifted the stay and dismissed the request for adjudicatory hearing on January 24, 2013 after a voluntary dismissal of the request had been submitted by the filer. Following these outcomes, a joint motion to dismiss the EPA appeal was granted by the Ninth Circuit on January 29, 2013.

2.2.4 The Existing 2015 Cook Inlet Exploration General Permit

Because the 2007 GP expired in 2012 and there was an emergent need for continued exploration in Cook Inlet, the exploration components of the expired 2007 GP were issued as two separate general permits in 2015, AKG315100 in State Waters by DEC (2015 Exploration

GP) and AKG285100 in Federal Waters by EPA (EPA Exploration GP). Essentially, reissuing these two GPs covered both the federal and state jurisdictions for exploration that were part of the 2007 GP. The 2015 Exploration GP retained the limitations included in the 2007 GP including standard-sized mixing zones, limits for domestic wastewater, characterization of miscellaneous discharges, prohibitions in coverage, and EMP requirements discussed in Section 2.2.3.1. DEC applied the chronic WET triggers previously used in federal waters in the 2007 GP, which were based on dilution factors at the boundary of a standard-sized 100 meter mixing zone based on modeling scenarios for various discharge flow rates for either submerged outfalls or surface discharges discharging at critical receiving water conditions. Although EMP Studies have been conducted under the 2015 Exploration GP, the sites have all been at locations were sediment is scoured out and collection of data has not been possible resulting in exemptions to post-drilling sampling [placeholder for Anita Research].

There are currently two effective authorizations under the 2015 Exploration GP: AKG315101 – BlueCrest Energy Alaska LLC (BlueCrest), Cosmopolitan Offshore and AKG315102 – Furie, Kitchen Lights Unit (KLU) Exploration. There are currently two MODUs that are potentially available to discharge under these authorizations: the Spartan 151 and the Randolph Yost. Although these authorizations are still active, there has not been exploration activities at the Cosmopolitan and none has occurred at the KLU at either location since 2016.

2.2.5 Sabre Exploration Project Individual Permit

CIE submitted an individual application to discharge from an exploration MODU within approximately 3,200 meters of the Trading Bay SGR on November 9, 2016 due to an inability to obtain an authorization under the 2015 Exploration GP for coverage within 4,000 meters of the SGR. Information submitted in the application indicated the Sabre Project Site was appropriate for receiving discharges of drilling fluids and drill cuttings. The site has adequate depth and current speeds to disperse the fluids and cuttings, there is no significant benthic community at the location due to transitional sediment conditions, and location is in proximity to existing fixed platforms and the TBPF where baseline environmental data has been collected and published in the Produced Water Study Report.

Based on the individual application, DEC issued Individual Permit AK0053690 – CIE, Sabre Exploration Project (Sabre IP) that became effective June 16, 2018. The Sabre IP was developed to be consistent with the 2015 Exploration GP and included requirements for conducting an EMP Study to evaluate the fate and effects of discharges of drilling fluids and drill cuttings. Development of the Sabre IP expanded upon previous mixing zone evaluations using new computer models in the Cornell Mixing Zone Model (CORMIX). Specifically, the mixing zone analysis verified the appropriateness of the 100 meter mixing zone that has been authorized based on empirical studies previously (Dames and Moore Continental Outer Stratigraphic Test (COST Study) Well report (1976)). In addition, a new module in CORMIX allows for modeling discharges directly to the water surface (e.g., noncontact cooling water). The 2007 GP used an approximated approach for similar discharges. Lastly, the Sabre IP met applicable water quality standards including the Antidegradation Policy.

2.2.6 KLU, Julius R Platform Individual Permit

In 2014, DEC issued an individual permit to Furie Operation Alaska, LLC (Furie), AK0053686 – KLU Gas Production Julius R Platform (Furie IP). The Furie IP was issued in lieu of authorization under the expired 2007 GP to support increased gas production in the Cook Inlet Region. The platform discharges domestic wastewater that meets secondary treatment standards, deck drainage, and fire control test water that does not contain chemical additives. All other platform wastes are either hauled to shore or transferred via the process pipelines with small volumes of produced water to the Furie GPF. Due to the low volume of

produced water produced from the Kitchen Lights Unit the Furie GPF does not discharge produced water. The Furie IP also included discharges associated with horizontal direction drilling (HDD) for gas pipeline construction from the Julius R Platform to the Furie GPF. HDD discharges similar to those under the Furie IP are anticipated to be needed to support future oil and gas development projects in Cook Inlet.

2.2.7 ExxonMobil AK LNG LLC Geotechnical Survey Individual Permit

In July 2015, DEC issued and individual permit AK0062278 - ExxonMobil AK LNG, LLC (EMALL), Cook Inlet Geotechnical Surveys (Geotech IP) to authorize the discharge of deck drainage and drilling fluids and drill cuttings associated with geotechnical surveys conducted in Cook Inlet. The Geotech IP was developed to support of preliminary design work for the construction of gas pipelines and terminal facilities for the AK LNG Project. A rotary drilling platform was used that required recirculation of drilling fluids to remove cuttings from borehole to the platform where the drilling fluid could be separated and recycled downhole and the cutting discharged overboard. Once the drilling ceases and the casing exits the seafloor the drilling fluids in the case would discharge to Cook Inlet. Two mixing zones sizes were authorized under the Geotech IP, one established based on critical currents on the east side of Cook Inlet and the other for the west side. During drilling of deep boreholes, unexpected artesian aquifers were encountered, which required cementing to abandon the wells per Alaska Department of Natural Resources (DNR) requirements. Once all reporting requirements had been met and the Geotech IP was no longer needed, it was terminated in November 2016.

2.2.8 Osprey Platform Individual Permit

The Osprey Platform was established onsite in 2000 and initially conducted exploration drilling under the 1999 GP. However, because the 1999 GP did not provide coverage for new production facilities north of Kalgin Island, the Osprey had to apply for an individual permit. In addition, with EPA as the permitting authority and production from the Osprey Platform was considered to be a New Source per 40 CFR 435.45, authorization of production discharges from the Osprey Platform required and Environmental Assessment (EA) under National Environmental Policy Act (NEPA). EPA conducted an EA and made a Finding of No Significant Impacts and issued individual permit AK0053309 – Osprey Platform to Pacific Energy Resources Limited at the time but now the owner is CIE, a subsidiary of Glacier Oil and Gas. The existing permit for the Osprey Platform was became effective in October 2009 (2009 Osprey IP) and has been administratively extended until DEC could either reissue the individual permit or authorize discharges from the Osprey Platform under the Cook Inlet Permit. Currently, DEC is taking both approaches, developing an individual permit for reissuance and including the same discharges for the Osprey in reissuance of the Permit.

The 2009 Osprey IP authorized discharges for deck drainage, domestic wastewater, and several miscellaneous wastes (desalination, boiler blow down, fire test water, noncontact cooling water, excess cement slurry, and waterflooding). Because the Osprey has four underground injection control (UIC) wells allowing for disposal, drilling fluid and drill cuttings, produced water, and many of the miscellaneous discharges have not historically been discharged from the Osprey Platform. However, CIE has submitted an application to discharge produced water due to infeasibility of continuing to inject produced water into the formation at the Osprey that is not only derived from oil production at the Platform but also from onshore wells in the West McArthur River Unit and the Redoubt Unit.

Currently, CIE injects 7,500 barrels per day (bbl/d) into four UIC wells located at the Osprey Platform, which represents maximum capacity and the formation that is being injected into has become over-pressurized. Installation of additional injection wells is not practicable due safety concerns related to well control if additional Class I UIC wells are drilled into the currently

over-pressurized shallow formation. In addition, further injection into the deeper oil producing formations will negate enhanced oil recovery; the ideal injection ratio is 1:1 for water injected to oil recovered. The discharge of produced water has become necessary in order to continue or expand oil production, which has economic and social benefits in the vicinity of the discharge.

2.3 Reissuance Plan and Stakeholder Involvement

2.3.1 The Stakeholder Workshop

Prior to initiating work on reissuing AKG315200, DEC conducted two stakeholder workshops, one in Anchorage on May 27, 2014 and one in Homer on May 29, 2014. Invitees included tribal government and municipal representatives, recreational and commercial fishing representatives, governmental agencies and Regional Citizens Advisory Councils, and active industry participants and potential future general permit applicants. The workshop framework included an educational component where DEC and EPA provided the regulatory and technical aspects of permit development, an overview of existing traditional knowledge discussions, and introduction of the concept of incremental improvements in environmental protection during permit development. After the educational segment, DEC solicited stakeholder's input into what aspects DEC should consider moving forward with reissuance. While there were many good improvements suggested, some were incompatible with DEC's authority (modifications of ELGs) or the regulatory process of the permit reissuance process (adopting fish consumption or new water quality criteria). Moving forward in collaboration with industry stakeholders, DEC chose the following general topics based on valuable input provided during the workshop:

- Incorporation of lessons learned from the 2007 GP and other Cook Inlet permits,
- Improved mixing zone analysis,
- Improved understanding of chemicals discharged,
- Critical review of the area prohibitions in relation to EMP Study objectives, and
- Develop pollution reduction strategies supporting the concept of incremental environmental protection.

2.3.2 Industry Stakeholder Collaboration

Since the workshops in 2014, DEC has been collaborating with applicants under the Permit to update information necessary to meet the objectives stemming from stakeholder input. Because HAK owns the majority of the platforms and all of the shore-based processing facilities, DEC collaborated extensively with HAK on permit development efforts to tailor portions of the Permit to more specifically fit the existing operations based on the details provided by the applicant. As a result, the pollution reduction requirements and monitoring requirements are more specific than was possible in previous permits that catered to numerous operators. DEC still requested the same information from other potential permittees but not to the extent with HAK due to their influence on the Permit.

Specifically, DEC requested HAK, and other applicants, to modify WET testing procedures from the pass/fail approach required by the 2007 GP to one that provides better characterization of chronic WET in the discharges of miscellaneous discharges and produced water. In addition, DEC required research into existing chemical uses and dosing practices for miscellaneous discharges that revealed a better understanding of effluent characteristics and led to development of pollution reduction strategies to be implemented during the term of the Permit. Using new data that was not previously available and incorporating significant updates to mixing zone modeling discussed in Section 6.2 resulted in most mixing zones being shorter but wider for produced water and with resulting effluents limits either being the same or more stringent than the 2007 GP. In addition, chemical use in miscellaneous discharges, dosing

practices, and revised mixing zone modeling has led to reduction in applicable dilution factors at the 100 meter boundaries. The standard-sized 100 meter mixing zone for discharge of drilling fluids and drill cuttings that have been based on empirical data has been verified using a new module in CORMIX. This validation was included in the Sabre IP where the 4,000 meter restriction to Trading Bay SGR disallowed coverage under the Exploration GP. When this drilling is conducted, the EMP Study may provide the first meaningful information on the fate and effects given the Sabre Project site conditions, characterized as having transitional (littoral drift) sediment transport. DEC is proposing to allow additional drilling within this vicinity under the Permit based on the information presented for the Sabre IP.

3.0 PERMIT COVERAGE

3.1 General

Once effective, the Permit will replace the portion of the 2007 GP that is applicable to state waters and the 2015 Exploration GP. In addition, discharges associated with pipeline construction and other ancillary activities (hydrostatic test water and HDD and geotechnical drilling fluids and drill cuttings) that are similar in nature to those in the 2007 GP are included. These additional discharges are included to more effectively cover discharges associated with development activities related to oil and gas and other resource projects in Cook Inlet that have discharges to those related to oil and gas. A complete list of discharges is available in Section 3.2.

3.2 Discharges

During the effective period of the Permit, permittees may be authorized to discharge pollutants associated with oil and gas exploration, development and production, and other ancillary projects with similar discharges, located in state waters in Cook Inlet within the limits and subject to the conditions set forth in the Permit. The Permit authorizes the discharge of only those pollutants resulting from facility processes, waste streams, and operations that have been identified during permit development or in the Notice of Intent (NOI) and described in a written authorization provided by the Department. To obtain authorization under the Permit, applicants must clearly demonstrate proposed sites are within the coverage area and meet all the requirements for coverage under the Permit as part of the NOI process. In certain situations where supplemental information may be necessary to obtain authorization (e.g., information needed to authorize a uniquely sized mixing zone), the applicant must submit adequate information that reasonably demonstrates compliance with 18 AAC 15 – Administrative Procedures, 18 AAC 70 – Alaska Water Quality Standards, 18 AAC 72 – Wastewater Disposal, or 18 AAC 83 – APDES Program. If the Department makes a determination that requires following administrative procedures (i.e., public notice), the Department may do so and provide conditions in the authorization issued to the permittee. The following wastewater discharges may be authorized under the Permit:

DISCHARGE NUMBER	DISCHARGES DESCRIPTION
001	Drilling Fluids and Drill Cuttings
002	Deck Drainage
003	Domestic Wastewater (as defined in 18 AAC 72.990(23))
004	Graywater (as defined in 18 AAC 72.990(35))
005	Desalination Unit Wastes
006	Blowout Preventer Fluid
007	Boiler Blowdown
008	Fire Control System Test Water
009	Noncontact Cooling Water

010	Uncontaminated Ballast Water
011	Bilge Water
012	Excess Cement Slurry
013	Fluids, Cuttings, and Cement at the Seafloor
014	Waterflooding (Filter Backwash)
015	Produced Water
016	Completion Fluids
017	Workover Fluids
018	Well Treatment Fluids
019	Test Fluids
020	Hydrostatic Test Water

3.3 Coverage Area

There are three zone classifications of waters within Cook Inlet: coastal, territorial sea, and offshore, which is within federal jurisdiction. Accordingly, the Permit covers only discharges to state waters, coastal water and territorial sea, while EPA covers discharges to federal waters. Coastal waters are defined as all of Cook Inlet north of the baseline at Kalgin Island and other embayments shoreward of other baselines (See Figure 1). The territorial sea is the first three nautical miles seaward from the Alaska coastline or a baseline. For the Permit, the coverage for discharge from oil and gas facilities that are applicable to 40 CFR 435 is being limited to only those locations that are within the most current lease boundary established by the Alaska Department of Natural Resources, Division of Oil and Gas. Discharges from HDD and geotechnical surveys that are not applicable to 40 CFR 435 are not being prohibited in any of the state waters of Cook Inlet as these discharges are intended to support a wide variety of projects.

3.3.1 Coverage Area Prohibitions for Oil and Gas Discharges

Certain environmentally sensitive areas are prohibited for certain discharges from oil and gas facilities, with a few conditions and exceptions. These prohibited areas and are generally shown on Figure 1 and discussed herein.

Water Depth Prohibitions: The Permit prohibits discharges of drilling fluids and drill cuttings from oil and gas facilities shoreward of the 10 meter isobath based on the mean lower low water (MLLW). All oil and gas facilities are prohibited to discharge any wastewater shoreward of the 5 meter isobaths. Discharges to these shallow waters disperse less than discharges to deeper waters and have greater potential to impact the abundant aquatic life found in these near shore locations.

Prohibitions for Environmentally Sensitive Areas: The Permit prohibits discharges from oil and gas facilities within the boundaries or within 4,000 feet of a river delta, or river mouth, or coastal marsh. For the Permit, coastal marshes are defined as the seaward edge of emergent wetland vegetation. The prohibition also applies to State Game Refuges (SGRs), state Critical Habitat A, Former Areas Meriting Special Attention (AMSA), and National Parks. The following lists some of the environmentally sensitive areas near or within the area of coverage:

Port Graham/Nanwalek AMSA,	Clam Gulch CHA,
Palmer Hay Flats SGR	Kachemak Bay CHA,
Susitna Flats SGR,	Redoubt Bay CHA
Trading Bay SGR,	Lake Clark National Park
Kalgin Island CHA,	

The 4,000 meter prohibition has exceptions in the following areas:

- The Trading Bay SGR which is restricted within 1,000 meters;
- Redoubt Bay CHA is restricted to within 1,000 meters at active leases 390,368.00 (Kustatan) and 381,203.00 (Osprey).

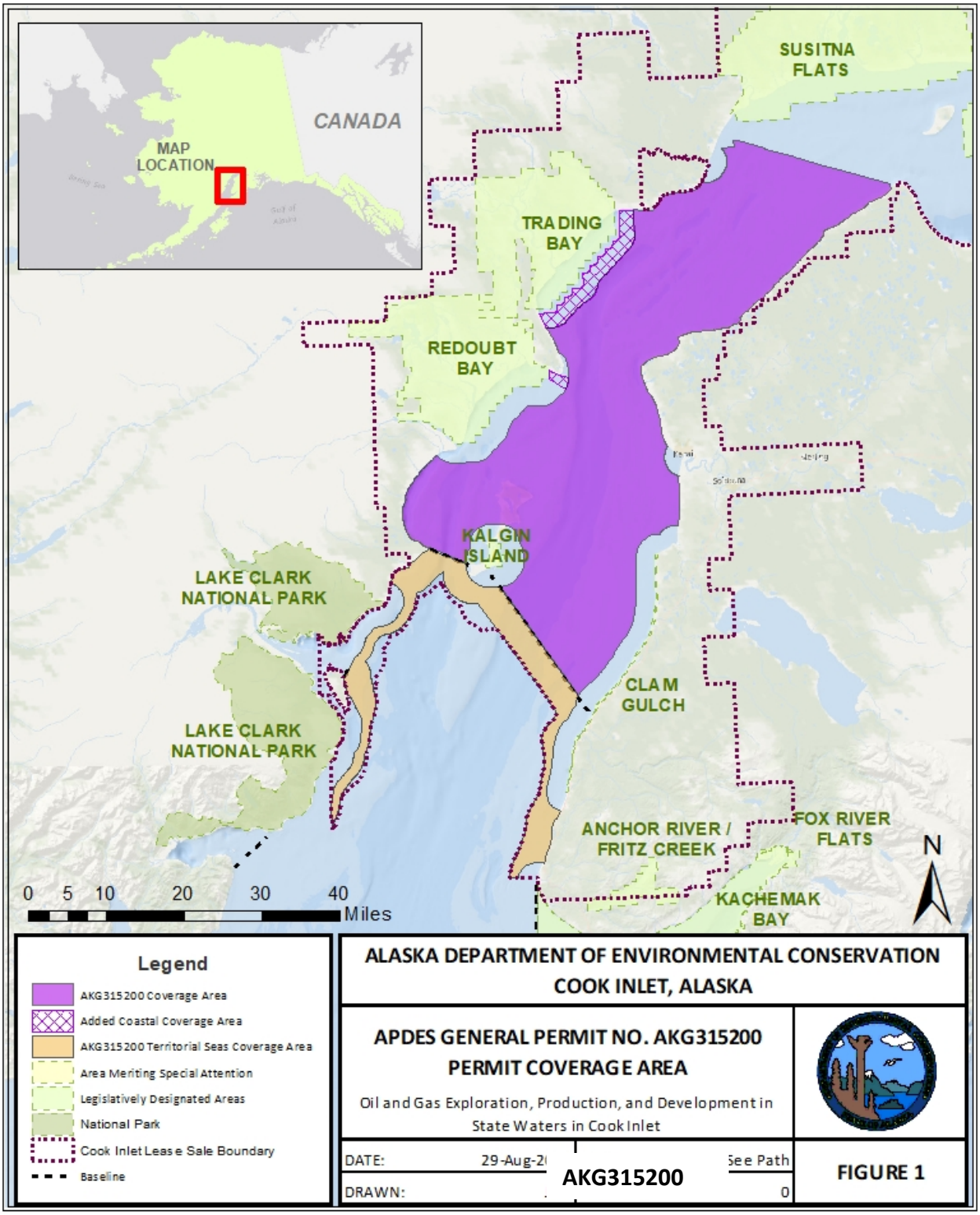
The Permit requires an EMP Study for discharging Class B2 or B3 drilling fluids and drill cuttings between 1,000 meters and 4,000 meters near the Trading Bay SGR and Redoubt Bay CHA. Discharges of Class B1 and all Class C drilling fluids and drill cuttings are allowed anywhere in state waters and the territorial seas. For information on the drilling fluid classifications see Section 4.1.4.

Discharges from oil and gas facilities are prohibited within tracts identified as being within Type 1 Beluga Critical Habitat Area in the Alaska Department of Natural Resources (DNR), Division of Oil and Gas (DOG) Mitigation Measure: Cook Inlet Areawide 2017W, revised April 2017.

The Permit prohibits discharges from oil and gas facilities in parts of Kamishak, Chinitna, and Tuxedni Bays because these are either areas of high resource value or are adjacent to areas of high resource value. In addition, Kamishak Bay is a known net depositional environment for sediment where drilling mud solids and other pollutants may potentially accumulate if discharges were authorized. The following describes these restricted areas in more detail:

- Kamishak Bay: West of a line from Cape Douglas to Chinitna Point.
- Chinitna Bay: Inside of the line between the points of the shoreline at latitude 59°52'45" N, longitude 152°48'18" W on the north and latitude 59°46'12" N, longitude 153°00'24"W on the south.
- Tuxedni Bay: Inside of the lines on either side of Chisik Island from latitude 60°04'06" N, longitude 152°34'12" W on the mainland to the southern tip of Chisik Island (latitude 60°05'45" N, longitude 152°33'30" W) and from the point on the mainland at latitude 60°13'45" North, longitude 152°32'42" West to the point on the north side of Snug Harbor on Chisik Island (latitude 60°06'36" N, longitude 152°32'54" W).

Figure 1: Area of Coverage Map



The Department of Environmental Conservation (DEC) has compiled the computer representation from data or information sources that may not have been verified by the DEC. This general representation should not be re-used without verification of sources by an independent professional qualified to verify such data or information. DEC does not guarantee the accuracy, completeness or timelines of the information shown and shall not be liable for any loss or injury resulting from reference upon the representation. Sources: Alaska Department of Natural Resources, Land Records GIS, National Marine Fisheries Service,

3.4 Facilities Covered Under Permit

Discharges from oil and gas exploration, development and production facilities, along with discharges from ancillary facilities that are necessary to support pipeline construction, HDD, and geotechnical surveys in state waters are eligible for coverage under the Permit.

3.4.1 Existing Fixed Facilities

Existing facilities that have been specified directly in the Permit include the following organized by whether or not a request to discharge produced water has been submitted:

Produced Water Requested	Produced Water Not Requested
GPTF	Anna Platform
TBPF	Spark Platform
MGS Onshore	Dolly Varden Platform
Baker Platform	MGS - A Platform
Bruce Platform	MGS - C Platform
Dillon Platform	Spurr Platform
GPP	King Salmon Platform
Tyonek A Platform	Grayling Platform
Osprey Platform	Monopod Platform
	Steelhead Platform
	Julius R Gas Production Platform

On this list, Anna Platform was previously authorized for produced water and the Osprey Platform was not. The Osprey Platform and the Julius R Gas Production Platform are currently authorized under individual permits but are anticipated to be transferred to the Permit once effective. At this time, Baker, Dillon, Spurr, and Spark Platforms have been placed in lighthouse status are not currently discharging, with the exception of deck drainage. However, it is possible that any of these facilities in lighthouse could become active during the term of the Permit.

3.4.2 Existing Exploration Projects using MODUs

Existing exploration projects using two MODUs that are either covered under an individual permits or authorized under the 2015 Exploration GP and are eligible for coverage under the Permit include: Sabre Exploration Project, Furie KLU Exploration, and BlueCrest Cosmopolitan Offshore. These existing authorizations are planned to be automatically covered under the Permit once effective.

3.4.3 New Fixed Oil and Gas Facilities

The 2007 GP did not allow for “New Sources” as defined in 40 CFR 435 to discharge produced water or drilling fluids and drill cuttings. “New Sources” are defined as any facility that discharges pollutants where construction commenced after the effective date of applicable New Source Performance Standards (NSPS), per 40 CFR 122.2. Construction of a New Source commences if the owner or operator of the facility (1) has begun, or caused to begin significant site preparation work as a part of a continuous on-site construction program or (2) has entered into a binding contractual obligation for the purchase of facilities or equipment that are intended to be used in its operations within a reasonable amount of time, per 40 CFR 122.29(b). Significant site preparation work means the process of surveying, clearing or preparing an area of the water body floor for the purpose of constructing or placing a development or production facility on or over the site. See 40 CFR 435.11(w)(1)(ii).

For Offshore Subcategory facilities (i.e., new facilities in the territorial sea), NSPS were promulgated on March 4, 1993 (58 Federal Register (FR) 12454 (Mar. 4, 1993). For Coastal Subcategory facilities (new facilities in Coastal Waters), NSPS were promulgated on December 16, 1996 (61 FR 66125 (Dec. 16, 1996). Therefore, any new development or production facilities in Cook Inlet are New Sources. Upon review of the applicable NSPS for offshore and coastal waters of Cook Inlet, implementation of the NSPS limitations does not changed the proposed limits or the implementation of the Permit. Therefore, this prohibition is being removed from the Permit. However, in situations where a new facility proposes to discharge produced water, DEC will require the applicant to submit an application (Form 1, Form 2C, and Form 2M) necessary to evaluate mixing zones and water-quality based limits. DEC determinations that will be placed in the authorization to discharge under the Permit will be provided in a Statement of Basis and issued for a 30-day public notice period following 18 AAC 15, 18 AAC 70, and 18 AAC 72, and 18 AAC 83 as applicable. The authorization may include additional conditions as an outgrowth of the administrative procedures.

3.4.4 New Oil and Gas Exploration MODUs and Projects

New Sources do not include new exploratory facilities because exploration is conducted at a particular site for a short duration and generally consists of drilling only one to five wells, see 59 FR 12454 (Mar. 4, 1993). In general, exploratory facilities differ from New Sources in that they do not have high volume discharges, and they do not discharge produced water. Moreover, the volume of drilling fluids and drill cuttings discharged from an exploratory facility is significantly less than from a development facility, where up to fifty wells can be drilled.

Exploration MODUs, as available and required, may seek coverage for marine discharges under the Permit by submitting an NOI and any required plans for Department review. The Permit covers discharges from MODUs when actively conducting drilling activities as determined by the MODU establishing itself over the drilling location or contacting the seafloor for setting up drilling. When moving to or from the exploration site, the MODU is considered to be in a mode of transportation and coverage under the EPA Vessel General Permit (VGP) is applicable. The typical drilling season for MODUs in Cook Inlet is generally April to October, or the months where ice-free water is anticipated. During the winter, MODUs are often warm or dry-stacked in a harbor or port. The Permit does not authorized incidental discharges from a MODU while in port. MODU operators should contact the port authority.

3.5 New Permit Conditions

3.5.1 Discharges of Non-Oil and Gas Drilling Fluids and Drill Cuttings

Construction of new port facilities or pipelines in Cook Inlet may require offshore geotechnical surveys and HDD. DEC defines a geotechnical facility as any floating moored, stationary jack-up rick or lift barge actively conducting geotechnical surveying in open water below the MLLW. Marine geotechnical programs typically use rotary drilling techniques that circulate drilling fluids to sweep cuttings out of the borehole to the deck of the facility. Drilling fluids are separated and recycled downhole and the cuttings discharged overboard. After drilling the borehole, the riser pipe is lifted and the remaining drilling fluids and drill cuttings are discharged to the surrounding marine water. Geotechnical surveys as described above, may obtain coverage under the Permit for Discharge 001 by submitting an NOI and any plan requirements based on the type of drilling fluid used. The Permit includes authorization of chronic mixing zones based on location in Cook Inlet: the east side receives one size mixing zone and the west side receives a different size. The mixing zones are based on those in AK0062278. Unlike MODUs, DEC assumes that incidental discharges from geotechnical facilities would be covered under the VGP but not the discharge of drilling fluids and drill cuttings associated with the geotechnical drilling.

HDD discharges typically occur from onshore facilities drilling out under the seafloor. An HDD example is pipeline construction that requires a transition from onshore to offshore, commencing from atop a bluff and penetrating to the seafloor. Upon breakthrough at the seafloor (daylighting), the drilling fluids that are under hydrostatic pressure are rapidly discharged initially and tapers of as a falling head discharge equilibrates to static pressure. The sizing requirements for HDD discharges can be too varied to consider a standardized mixing zone. Therefore, the authorized of HDD discharges for Discharge 001 under the Permit requires submittal of a mixing zone application, Form 2M, along with an NOI and Drilling Fluids Plan (DFP). After developing a Statement of Basis and following public notice procedures, an authorization can be issued to include a facility-specific mixing zone.

3.5.2 Discharges of Hydrostatic Test Water

Hydrostatic discharges were allowed in the 2007 GP so long as it was commingled with produced water. The Permit specifically authorizes the Discharge 020 – Hydrostatic Test Water and expands to include hydrostatic testing or flushing of potable water systems on fixed platforms and MODUs. Authorization can be obtained by submitting an NOI for hydrostatic test water commingled with produced or test water from potable or clean infrastructure discharged directly to Cook Inlet. For existing pipelines where the hydrostatic test water has hydrocarbon contamination and is proposed to be discharged directly rather than commingled with produced water, the applicant must submit treatment best management practices (BMPs) that demonstrate the ability to remove free-phase and dissolved phase hydrocarbons with the NOI for Department approval prior to obtaining authorization.

3.5.3 Commingling Excavation Dewatering from Contaminated Sites with Produced Water

The 2007 GP allowed for commingling of water from a contaminated site located at the TBPF with produced water. The water from the contaminated site is treated by the facility and regulated as produced water. Similarly, the 2007 GP allowed for commingling of spill clean-up waste for treatment in the produced water system. A notification was required 24 hours within 24 hours of the treatment followed by a written submission that described the spill, anticipated volume of spill clean-up water, and anticipated duration that the treatment and discharge of spill clean-up water is expected to continue. Given the precedent of treating contaminated water and spill waste in the 2007 GP, DEC is including the ability of the permittee to include excavation dewatering water that is contaminated with hydrocarbons to be treated and disposed with produced water at onshore facilities such as TBPF, MGS Onshore, GPTF or new facilities. Prior to commingling, the permittee is required to contact the DEC Contaminated Sites Program (CSP) and the Wastewater Discharge Authorization Program to obtain written approval on a case-by-case basis (See Permit Section 2.7.5).

3.5.4 Clarifications and Discussion on Domestic Wastewater and Graywater Discharges

3.5.4.1 Clarifications for Domestic Wastewater per 18 AAC 72

This section provides definitions and clarifications associated with Discharge 003 – Domestic Wastewater and Discharge 004 – Graywater to assist in understanding distinct differences between the permits developed by DEC and previous permits by EPA. The Permit defines graywater per 18 AAC 72.990(35), which is consistent with the definition for domestic wastewater established in the Oil and Gas Extraction Point Source Category, 40 CFR 435.11(j) for the Offshore Subcategory and 40 CFR 435.41(l) for the Coastal Subcategory as adopted by reference at 18 AAC 83.010(g)(3). Graywater (analogous to domestic wastewater in EPA permits) is defined as: “the materials discharged from sinks, showers, laundries, safety showers, eye-wash stations, hand-wash stations, fish cleaning stations, and galleys located within facilities subject to this Subpart.”

The greatest point of divergence between the Permit and the 2007 GP is in how the state defines domestic wastewater and the implications toward graywater. The state regulatory definition of domestic wastewater in 18 AAC 72.990(23) includes graywater and black water, or in EPA terms domestic and sanitary wastes, respectively. Per 40 CFR 435, sanitary waste and domestic waste require different pollution control measures. However, under state authority graywater is subject to the same regulatory requirements as domestic wastewater that contains black water only, or commingled black and graywater. The ramifications of this difference is that per 18 AAC 72.050, domestic wastewater discharges must meet minimum treatment requirements (i.e., secondary treatment per 18 AAC 72.990(59)) unless a waiver from minimum treatment is granted by the Department under 18 AAC 72.060. If a waiver is granted, the discharge has to meet at least primary treatment as defined in 18 AAC 72.990(50) as attaining 30 % removal of BOD5 and TSS. Hence, graywater discharges require at least primary treatment (e.g., settling or filtration) in order to be discharged as graywater. For existing Cook Inlet Platforms, graywater typically has not been treated to primary standards nor have waivers to minimum (secondary treatment) standards been obtained. For black water discharges, limits have been established in previous Cook Inlet general permits that do not meet secondary standards. However, in these cases most have received a waiver to secondary standards. During the issuance of the CWA 401 Certification of Reasonable Assurance for the 1999 GP, DEC granted a categorical waiver from secondary treatment to for facilities that treat domestic wastewater using a biological treatment unit (BTU) or a combination of marine sanitation device (MSD) and BTU (MSD/BTU) and is staffed with 10 people or less. This waiver applies to Anna, Baker, Bruce, and Dillon Platforms for Discharge 003 – Domestic Wastewater. However, this Certification did not include waivers to secondary treatment for Discharge 004 - Graywater. Lastly, the Randolph Yost MODU received a waiver for secondary treatment for Discharge 003 – Domestic Wastewater on April 22, 2016 and the Spartan 151 received a waiver to secondary treatment for Discharge 004 – Graywater on February 20, 2018. See Section 4.3 and Table 8 for a complete list.

3.5.4.2 Discussions on Interim Approach to Permitting Domestic Wastewater

The domestic wastewater systems on the older, existing fixed platforms in Cook Inlet were constructed to satisfy 40 CFR 435 and Coast Guard regulations that require marine sanitation devices (MSDs) to treat black water and graywater is typically over-boarded without treatment. The typical MSD was not sized to treat black water combined with graywater and were installed in small areas of the platform that leave little space for expanding treatment to meet secondary treatment requirements. Although the collection system piping for black water is typically adequate to route all black water to MSDs, graywater piping is often discontinuous with multiple discharge locations on the platform. The discontinuous graywater piping means that either a significant amount of effort has to be expended on trying to modify piping or multiple primary treatment systems have to be installed at each discharge. Hence, attempting to satisfy primary treatment objectives in order to receive a waiver to secondary treatment for discharging graywater proves challenging and inherently impracticable. Some of the existing fixed platforms and exploration MODUs operating in Cook Inlet have received waivers.

To address graywater discharges from several existing fixed platforms that have not received a waiver to secondary standards, DEC is requiring the permittees for these existing fixed platforms to conduct characterization and evaluation of each of their affected graywater discharges to provide information for the Department to consider during the next reissuance of the Permit. First, graywater effluent characterization is required that can be used to quantify and qualify environmental concerns of the existing graywater discharges. Second, the permittees must evaluate existing infrastructure and provide up to date line diagram or

conceptual drawings that can be used to render decision on the practicality of potential upgrade alternatives. The objective is to evaluate practicable alternatives that could lead to prioritized incremental improvements and support future alternative analysis or support regulatory decisions. Treatment alternatives should consider either commingling graywater with the Discharge 003 either before treatment or after treatment or meeting primary treatment requirements with just graywater discharges (See Section 11.7).

Until more information is available, limits for BOD_5 and TSS established in the 1999 GP for Discharge 003 – Domestic Wastewater are being retained in the Permit for existing platforms and existing exploration MODUs. Similarly, requirements for Discharge 004 – Graywater remain unchanged in the Permit for existing platforms and exploration MODUs. However, any new platforms or MODUs must comply with the most current version of 18 AAC 72 as it applies to domestic wastewater, including graywater meeting primary treatment and obtaining a waiver to secondary treatment.

3.5.5 Pollution Reduction Best Management Practices for Miscellaneous Discharges

Given the 2007 GP was not structured to adequately characterize chronic toxicity from chemical use in Discharges 005 – Desalination Waste, 009 – Noncontact Cooling Water, and 014 – Waterflooding, DEC is modifying chronic WET monitoring requirements and linking it to pollution reduction (PR) BMPs to attempt to adequately determine and incrementally reduce, or eliminate, toxicity in these discharges during the term of the Permit. The requirement to monitor chronic WET for discharges that have chemical additives and discharge greater than 10,000 gpd is retained. However, the permittee will be required to evaluate sample collection techniques to ensure representation of actual toxicity in the effluent. The chronic WET dilution series will focus on bracketing observed toxicity from previous WET results. Observations of elevated toxicity will require revising and implementing BMPs to reduce toxicity in subsequent WET monitoring.

Based on improved mixing zone analysis and better understanding of the specific chemicals currently being used in these discharges, PR BMP Revision Action Levels have been developed based on meeting chronic WET criteria at the boundary of a 100 meter mixing zone. In addition, the permittees must develop and implement BMPs to optimize chemical dosing procedures to ensure toxicity is minimized while maintaining effective chemical treatment objectives. If a PR BMP Revision Action Level is exceeded, the permittee must revise the BMP to achieve less toxicity. These BMPs could be operational or physical modifications to the chemical dosing system. Exceeding a PR BMP Revision Action Level also triggers a requirement for the permittee to evaluate the system and initiate an update to line drawings as part of the BMP Plan. Regardless of exceeding a PR BMP Revision Action Level, the permittees will be required to submit updated line drawings of the discharge piping systems for each authorized discharge where chemicals are used and discharge greater than 10,000 gpd with the next application for reissuance. Hence, exceeding a PR BMP Revision Action Level places priority on those systems that are problematic. The submittals of updated line diagrams will information to DEC on the system and any chemical additives, dosing practices, and sampling locations. In addition, these drawings will improve understanding of comingled discharges and will make re-application for future permits more streamlined. For those discharges that have WET testing requirements, the updated line drawings will also be used to evaluate the potential for reducing WET testing frequency.

As an incentive to PR, if the permittee demonstrates that sampling procedures were adequate to collect a representative sample and toxicity does not exceed PR BMP Revision Action Levels in two consecutive WET monitoring events, they can submit a request for monitoring frequency reduction. Only one step reduction may be granted by DEC during the term of the Permit.

3.5.6 Produced Water Chronic WET Notification Levels

During review of the existing chronic toxicity data for produced water, DEC found that the same pass/fail approach applied to miscellaneous discharges were also applied to produced water and also resulted in poor characterization information. Similar to miscellaneous discharges, DEC requested modifications to the dilution series in recent chronic toxicity tests for produced water to get a better understanding of chronic toxicity. Once this new data was obtained, DEC evaluated the approach used in the 2007 GP concerning establishing triggers based on mixing zones, and associated limits. Essentially, the established triggers were much higher than the actual observed toxicity in the recent test such that is seemed unrealistic that triggers would ever be exceeded that would require evaluation of causal circumstances and retesting, or accelerated testing if repeated tests also exceed triggers. In addition, implementation toxicity identification evaluations (TIEs) and toxicity reduction evaluations (TREs) were required in the 2007 GP in the event that accelerated test continued to exceed the triggers. DEC considered there may be a better approach to control chronic toxicity and work toward toxicity reduction.

The Permit has not retained the previous high triggers. Instead, DEC applies statistical procedures to the available data to establish notification levels that are lower than previous triggers. DEC still requires evaluation of the cause and repeat tests if chronic toxicity results exceed the notification levels but accelerated testing and TRE/TRI requirements have been removed. DEC retains authority in the Permit to require accelerated testing or TRE/TIE if necessary by imposing additional monitoring requirements per Section 8.12.

3.6 Notice of Intent, Applications, and Authorizations

The Permit is structured to provide expedited authorizations for existing facilities that have been identified and addressed in site-specific evaluations during the permit development process. For example, site-specific mixing zones have been developed for existing facilities such that additional information during the NOI process is not warranted. In addition, standardized mixing zones have been adequately evaluated such that the NOI process provides sufficient information to ensure that most new facilities submitting an NOI can be verified to be consistent with permit conditions in order to receive authorizations. However, there are a few situations where permit development could not adequately account for unique conditions that would result in expedited authorizations. In these few situations, DEC allows submittal of additional information to develop specific conditions that can be included in authorizations after developing a statement of basis and following appropriate administrative procedures (e.g., public notice of Department determinations). Lastly, certain discharges may require plans that are unique to the discharge or discharge location (i.e., EMP Study Plans and DFPs). The following sections provide an overview of the NOI process and when additional information may be needed to support an authorization under the Permit.

3.6.1 Exploration MODUs

3.6.1.1 NOI Requirements for Existing Exploration MODUs at Existing Locations

Existing Exploration MODUs with existing authorizations for specific sites identified in Section 3.4.2 will be automatically authorized under the Permit upon the effective date and issuance of a replacement written authorization by DEC. Upon receiving a replacement authorization under the Permit, the 2015 Exploration GP and associated existing authorizations will be terminated.

3.6.1.2 NOI Requirements for New Exploration MODUs or Existing MODUs at New Sites

New exploration MODUs or existing exploration MODUs requesting authorization to discharge at a new location must submit an NOI 45 days prior to discharge. If the location is

within 4,000 meters of the Trading Bay SGR or Redoubt CHA, a DFP and EMP Study Plan must be submitted with the NOI for Department review.

3.6.2 Fixed Development and Production Platforms and Onshore Facilities

3.6.2.1 NOI Requirements for Existing Fixed Platforms and Onshore Facilities

Existing fixed platforms identified in Section 3.4.1 currently authorized under an individual permit may submit an NOI for coverage under the Permit. Upon receiving a written authorization to discharge under the Permit and compliance with the existing IP is verified to be current, DEC will terminate the superseded individual permit. Those facilities in Section 3.4.1 that are currently authorized under the 2007 GP must submit an NOI for coverage within 30 days of the effective date of the Permit. Once DEC issues a written authorization, the existing authorizations under the 2007 GP will be terminated.

3.6.2.2 NOI Requirements for New Fixed Platforms and Onshore Facilities

3.6.2.2.1 New Fixed Platforms or Onshore Facilities without Produced Water Discharges

New fixed platforms or onshore production facilities that are not seeking authorization to discharge produced water (Discharge 015) under the Permit must submit an NOI requesting coverage within 45 days from discharging. If appropriate, DEC will issue a written authorization establishing the effective date of the authorization and any conditions.

3.6.2.2.2 New Facilities or Existing Facilities with New Produced Water Discharges

New fixed platforms, onshore production facilities, or existing facilities not included in Section 8.6.7 that are proposing to discharge produced water must submit an individual permit application (Form 1, Form 2C, and Form 2M) within 1 year prior discharging. If appropriate, DEC will issue a written authorization establishing specific conditions and the effective date of the authorization after developing a Statement of Basis following applicable administrative procedures in 18 AAC 15, 18 AAC 70, and 18 AAC 83. Alternatively, DEC may require an individual permit.

3.6.3 NOI Requirements for HDD Projects

HDD Projects that are seeking authorization to discharge drilling fluids and drill cuttings (Discharge 001) under the Permit must submit an NOI, DFP (if applicable per Section 11.6.1), and a mixing zone application (Form 2M) within 120 days prior to discharging. If appropriate, DEC will issue a written authorization establishing project specific discharge conditions and the effective date of the authorization after developing a Statement of Basis following applicable administrative procedures in 18 AAC 15, 18 AAC 70, and 18 AAC 83.

3.6.4 NOI Requirements for Geotechnical Survey Projects

Geotechnical Survey Projects that are seeking authorization to discharge drilling fluids and drill cuttings (Discharge 001) under the Permit must submit an NOI and DFP (if applicable per Section 11.6.1) within 45 days prior to discharging. If appropriate, DEC will issue a written authorization establishing project specific discharge conditions and the effective date of the authorization.

3.6.5 EMP Study Plan Requirements

The Permit requires the applicant to submit an EMP Study Plan with the NOI for review and approval by the Department if the applicant proposes to discharge Class B2 drilling fluids and the discharge location is within 4,000 meters of the Trading Bay SGR or Redoubt CHA. The Department also requires the applicant to provide copies of any exploration plans, biological surveys, and environmental reports required by DNR or the Corps of Engineers for the identification or protection of biological populations or habitats. If these documents do not

exist, the Permit requires the applicant to provide notice that such documents do not exist.

3.6.6 Drilling Fluid Plan Requirements

DFPs were required in the 2015 Exploration GP and accompanied EMP Study Plans. Similar to EMP Study Plans, a DFP must be submitted with the NOI when discharges of Class B2 drilling fluids and drill cuttings from exploration MODUs occurs within 4,000 meters of the Trading Bay SGR or Redoubt CHA.

For HDD and Geotechnical Surveys, DFPs have been required for individual permits to support the application process. The Permit also requires DFPs be submitted with NOIs for HDD Projects or Geotechnical Surveys that propose to discharge Class C2 or C3 drilling fluids and drill cuttings. Although DFPs are not required for Class B1 or C1 drilling fluids, DEC recommends DFPs be developed if it is likely the permittee may request additional chemical additives during the project such that toxicity could shift the classification to one that requires a DFP. DEC approval is required prior to implementing these plans.

3.6.7 Cooling Water Intake Structures

The applicant must verify whether their oil and gas facility meets the applicability criteria for new offshore oil and gas extraction facilities and, if so, whether it will comply with Track II requirements from 40 CFR 125, Subpart N. This verification is part of the NOI or application procedure. Regardless, the permittee must develop facility-specific BMPs for intake structures per Section 11.3.1.6.

3.6.8 Oil and Gas Exploration Wells

The Permit requires the applicant to submit the following for each exploration well: the initial date of drilling; the well name; the well number (i.e., #1, #2, etc.); the well hole diameter; the type of fluids used (e.g., water-based, oil-based, synthetic-based, etc.); class of fluid per Section 4.1.4, the type or group of fluid used (e.g., lignosulfonate muds, lime muds, etc.); the solids removal process; and the certification of a complete DFP, if applicable.

3.6.9 Domestic Wastewater Discharges

The Permit requires the applicant to identify the types of discharges from the facility. In addition, the Permit requires the applicant to indicate the type of sanitary discharge that will occur, if any (i.e., M10 or M9IM).

3.6.10 Line Drawing for New Facilities

The NOI or individual application requires the applicant to submit a line drawing showing depicting waste streams from new facilities including estimated flow rates and other information necessary to characterize the discharges, including sampling locations.

3.6.11 Plan Approval and Waivers for First Time Applicants

For new domestic wastewater discharges (black or graywater) under the Permit, the applicant must comply with the most current version of 18 AAC 72. Plan approval may also be required before constructing, installing, or modifying any part of a domestic wastewater collection, treatment, or disposal system. In addition, a permittee that constructs, alters, installs, modifies, or operates a non-domestic wastewater treatment works or disposal system may be required to obtain written approval of plans or prior to implementing treatment systems in BMP Plans. Contact DEC for determination of requirements prior to submitting NOIs and applications for new facilities.

3.6.12 Date of Authorized Discharge

18 AAC 83.210(f) requires a general permit to specify the date(s) when it authorizes a permittee to begin discharging. Commencement of discharges from a facility may occur any time after issuance date of a written authorization from DEC. The written authorization will

assign the facility an APDES permit authorization number for the site specified in the NOI.

3.6.13 Revised Authorizations

The permittee with an existing authorization under the Permit may revise their authorization by submitting updated NOI with the new information.

3.6.14 Transfers

Per 18 AAC 83.150, coverage for a given facility to be transferred from an existing owner to a new owner. The Permit authorizes a transfer only for an existing facility located at the same site clearly designated in the original NOI. Discharge authorizations for a particular facility may not be transferred to another facility at the same site, nor will the transfer apply to the same facility at a new location.

3.6.15 Termination Notification

DEC may terminate coverage under an APDES permit for the reasons described in 18 AAC 83.140 using the procedures provided in 18 AAC 83.130. If a permittee desires to terminate coverage, the Permit requires the permittee to provide notice of termination (NOT) to DEC within 30 days following cessation of discharges. The notice must include certification that the facility is not subject to an enforcement action or citizen suit. The notice must also include any final reports required by the Permit.

4.0 WASTEWATER CHARACTERIZATION

4.1 Drilling Fluids and Drill Cuttings

The Department has evaluated drilling fluids and found that they can be used for a variety of reasons, including oil and gas and other drilling activities. Common non-oil and gas drilling includes, but is not limited to, geotechnical borings for core sediment sample collection, HDD for installation of utility line crossings to avoid surface features and onshore to offshore transitions for pipeline construction, and borings for vertical support members or cathodic protection. Oil and gas activities include drilling wells for exploration, development, production, and injection wells. Drilling fluids used for oil and gas are regulated under 40 CFR 435; whereas, non-oil and gas drilling fluids are not.

4.1.1 Mobile Offshore Drilling Units

Mobile exploration activities in Cook Inlet to date have been undertaken by various MODUs including drill ships, jackup rigs, and semisubmersible rigs. Drill ships and ship-shaped barges are vessels equipped with drilling rigs that float on the surface of the water, and maintain their position by dynamic positioning and anchors on the seafloor. A jackup rig consists of a drill rig attached to a barge. Once the rig reaches its desired location, support legs are jacked downward to the seafloor. Once the legs reach the seafloor, the downward pressure of the jacking process lifts the barge out of the water. Semisubmersible rigs are mounted to a hull with adjustable ballast, allowing the hull to be raised or lowered within the water. The rig floats on top of the water when not in use. Once the hull is flooded, it lowers to a depth that allows the rig to remain stable against wave motion (DEC 2015). These drilling operations will result in similar, if not identical types of discharges.

4.1.2 General Drilling Fluids and Drill Cuttings Characteristics

The term drilling fluids (or drilling muds) refer to a suspension of solids and dissolved materials in a base fluid (e.g., water, oil, or synthetic base). Drilling fluids are an emulsion or a mixture in which one liquid, the dispersed phase, is uniformly distributed (usually as minute globules) in another liquid, the continuous phase. Drilling fluids are specifically formulated for each wellbore to meet unique physical and chemical requirements and to perform specific

functions. The wellbore location, depth, rock type, and other conditions are all considered to develop a drilling fluid with the appropriate viscosity, density, sand content, and gel strength (Schlumberger 2015). In general, drilling fluids are designed to perform one or more of the following primary functions:

- Remove cuttings and transport them to the surface,
- Cool and clean the drill bit,
- Lubricate the drill string,
- Maintain the stability of uncased sections of the borehole, and
- Counterbalance formation pressure to prevent formation fluids (i.e., oil, gas and water) from entering the well prematurely (Berger and Anderson 1992).

Drill cuttings are rock particles broken loose by the drill bit and carried to the surface by drilling fluids that circulate through the borehole. The cuttings are composed of the naturally occurring solids found in subsurface geologic formations and, to a much lesser extent, bits of cement used during the drilling process. Discharged drill cuttings usually contain about 10 to 15 % adsorbed drilling fluid solids (Neff 2008). A shale shaker and other solids control equipment separate cuttings from the drilling fluids so the drilling fluids can be circulated back down the borehole.

For water-based fluids (WBFs) as defined by 40 CFR 435.41(n)(1)), water is the suspending medium for solids and is the continuous phase. These fluids are composed of approximately 50 % to 90 % water by volume, with additives comprising the rest. WBFs are used most frequently because they are the least expensive, although they are not always the most effective. Reactivity with clay shale can cause destabilization of the borehole. WBFs can cause reactivity with some shale formations and may not have sufficient lubricity to avoid sticking of the drill pipe in deep boreholes or high-angle directional drilling. There are eight generic types of WBFs (EPA 1993):

1. Potassium/polymer fluids are inhibitive fluids because they do not change the formation after it is cut by the drill bit. Inhibitive fluids slow or stop hydration, swelling, and disintegration of shales. This fluid is used in soft formations such as shale, where sloughing may occur.
2. Seawater/lignosulfonate fluids are inhibitive fluids that maintain viscosity by binding lignosulfonate cations onto the broken edges of clay particles. This fluid is used to control fluid loss and to maintain borehole stability. This type of fluid can be easily altered to address complicated drilling conditions, like high temperature in the geologic formation.
3. Lime (or calcium) fluids are inhibitive fluids that change viscosity as calcium binds clay platelets together to release water. This fluid can maintain more solids and is used in hydratable, sloughing shale formations.
4. Non-dispersed fluids are used to maintain viscosity, to prevent fluid loss, and to provide improved penetration, which may be impeded by clay particles in dispersed fluids.
5. Spud fluids are non-inhibitive fluids that are used in approximately the first 300 meters of drilling. This is the most basic fluid mixture, and it contains mostly seawater and few additives.
6. Seawater/freshwater gel fluids are inhibitive fluids used in early drilling to provide fluid control, shear thinning, and lifting properties for removing cuttings from the hole. Prehydrated bentonite is used in both seawater and freshwater fluids, while attapulgite is used in seawater when fluid loss is not a concern.

7. Lightly treated lignosulfonate freshwater/seawater fluids resemble seawater/ lignosulfonate liquids, except that their salt content is less. Lignosulfonate or caustic soda controls the viscosity and gel strength of this fluid.
8. Lignosulfonate freshwater fluids are similar to the fluids described in 2 and 7 above, except the lignosulfonate content is higher. This fluid is used for high temperature drilling.

The composition of drilling fluids can be adjusted over a wide range from one borehole to the next, as well as during the course of drilling a single borehole when encountering different formations. In addition, additives can be used to adjust properties of generic fluids depending on particular needs within the drilling process. The list below presents some of the more common additives used.

- Weighting materials, primarily barite (barium sulfate), are commonly used to increase the density of the drilling fluid in order to equilibrate the pressure between the borehole and formation when drilling through particularly pressurized zones.
- Corrosion inhibitors such as iron oxide, aluminum bisulfate, zinc carbonate, and zinc chromate protect pipes and other metallic components from acidic compounds encountered in the formation.
- Dispersants, including iron lignosulfonates, break up solid clusters into small particles so that the fluid can carry them.
- Flocculants, primarily acrylic polymers, cause suspended particles to group together so they can be removed from the fluid at the surface.
- Surfactants, like fatty acids and soaps, are used to defoam and emulsify the drilling fluid.
- Biocides, typically organic amines, chlorophenols, or formaldehydes, kill bacteria that may produce toxic hydrogen sulfide gas.
- Fluid loss reducers include starch and organic polymers. These limit the loss of drilling fluid to under-pressurized or high-permeability formations (EPA 1987).

Table 1 provides formulations for four common generic fluids with additives.

Table 1: Generic Fluid Formulations

Seawater/Potassium/ Polymer Fluid		Seawater/Freshwater Gel Fluid		Seawater Lignosulfonate Fluid		Lime Fluid	
Components	**lb/bbl**	**Components**	**lb/bbl**	**Components**	**lb/bbl**	**Components**	**lb/bbl**
Potassium Chloride (KCl)	5–50	Attapulgite or Bentonite Clay	10–50	Attapulgite or Bentonite	10–50	Lime	2–20
Starch	2–12	Caustic	0.5–3	Lignosulfonate	2–15	Bentonite	10–50
Cellulose Polymer	0.25–5	Cellulose Polymer	0–2	Lignite	1–10	Lignosulfonate	2–15
Xanthan gum Polymer	0.25–2	Drilled Solids	20–100	Caustic	1–5	Lignite	0–10
Drilled Solids	20–100	Barite	0–50	Barite	25–450	Barite	25–180
Caustic	0.5 –3	Soda Ash/ Sodium Bicarbonate	0–2	Drilled Solids	20–100	Caustic	1–5
Barite	0–450	Lime	0 –2	Soda Ash/ Sodium Bicarbonate	0–2	Drilled Solids	20–100
Seawater	As Needed	Seawater/ Freshwater	As Needed	Cellulose Polymer	0.25–5	Soda Ash/ Sodium Bicarbonate	0–2
lb/bbl = pounds per barrel Source: EPA 1985				Seawater	As Needed	Seawater	As Needed

The following specifically describes additives and their purposes.

Lignosulfonate is made from the sulfite pulping of wood chips used to produce paper and cellulose is used to control viscosity in drilling fluids by acting as a thinning agent or deflocculant for clay particles. Concentrations in drilling fluid range from 1 to 15 lb/bbl. Ferrochrome lignosulfonate, the most commonly used form of lignosulfonate, is made by treating lignosulfonate with sulfuric acid and sodium dichromate. The sodium dichromate oxidizes the lignosulfonate and promotes cross linking. Chromate supplies the hexavalent chromium that is reduced during reaction to the trivalent state and complexes with the lignosulfonate. At high downhole temperatures, the chrome binds onto the edges of clay particles and reduces the formation of colloids. Ferrochrome lignosulfonate retains its properties in high-soluble salt concentrations and over a wide range of alkaline pH (EPA 1993).

Sodium hydroxide (caustic soda) is used to maintain pH between 9 and 12. A pH of 9.5 provides maximum deflocculation and keeps the lignite in solution. A more basic pH lowers the corrosion rate and provides protection against hydrogen sulfide contamination by limiting microbial growth (Lyons 2009).

Zinc carbonate is used as a sulfide scavenger when formations containing hydrogen sulfide are expected to be encountered during drilling. The zinc sulfide and unreactive zinc compounds are discharged with the drilling fluid, thus contributing to the overall loading of zinc when they are used. While the potential need exists, most drilling activities do not encounter conditions that warrant the addition of sulfide scavengers (Lyons and Plisga 2005).

Barite is a chemically inert mineral that is heavy and soft, and is the principal weighting agent in WBFs. Barite is composed of over 90 % barium sulfate, which is virtually insoluble in seawater, and is used to increase the density of the drilling fluid to control formation pressure (Perricone 1980, cited in Neff 1981). Barite can also contain quartz, chert, silicates, other minerals, and trace levels of metals. Some trace metals in drilling fluids containing barite can

adhere to cuttings including, but not limited to, mercury, cadmium, arsenic, chromium, copper, lead, nickel, and zinc (EPA 2000). Barite ore, the natural source of barium sulfate, has also been shown to contain varying concentrations of metals depending on the characteristics of the deposit from where the barite was mined.

A statistical analysis on the American Petroleum Institute (API)/EPA Metals Database indicates there is some correlation between cadmium and mercury with other trace metals in the barite as described in the ELG Development Document (EPA 821-R-93-003, January 1993 [EPA 1993]) for the Offshore Category. Specifically, EPA evaluation showed a correlation between the concentration of mercury with the concentration of arsenic, chromium, copper, lead, molybdenum, sodium, tin, titanium and zinc. The analysis also demonstrated a correlation between the concentration of cadmium with concentrations of arsenic, boron, calcium, sodium, tin, titanium and zinc. Based on these correlations, 40 CFR 435 requires stock barite to meet the limits of 3.0 milligrams per kilogram (mg/kg) for cadmium and 1.0 mg/kg for mercury. Hence, the ELGs use cadmium and mercury limits as surrogates for controlling the other trace metals present in barite. Table 2 below presents the metals concentrations in barite that were the basis for the cadmium and mercury limits in the ELGs.

Table 2: Metals Concentrations in Barite Used in Drilling Fluids

Metal	"Clean" Barite Concentrations (mg/kg)	Metal	"Clean" Barite Concentrations (mg/kg)	Metal	"Clean" Barite Concentrations (mg/kg)
Aluminum	9,070	Chromium	240	Selenium	1.1
Antimony	5.7	Copper	18.7	Silver	0.7
Arsenic	7.1	Iron	15,344	Thallium	1.2
Barium	359,747	Lead	35.1	Tin	14.6
Beryllium	0.7	Mercury	0.1	Titanium	87.5
Cadmium	1.1	Nickel	13.5	Zinc	200
Source: EPA 1993; Table XI-6					

After promulgation of 40 CFR 435, some barite sources have been replaced with sources containing less metal content in order to meet ELGs. Table 3 provides a summary of the average metal concentrations of barite and WBFs used after 1993 in the U.S. and North Sea drilling operations (Neff 2010).

Table 3: Average Metal Concentrations in Barite and WBFs

Metal	Barite	WBFs	Metal	Barite	WBFs
Arsenic (mg/kg)	1 – 2.2	4.4 – 10.0	Lead (mg/kg)	18 – 318	2.3 – 40
Barium (mg/kg)	503,000	12,500 – 179,000	Mercury (mg/kg)	0.05 – 0.44	0.08 – 0.15
Cadmium (mg/kg)	0.05 – 0.35	0.84 – 1.75	Nickel (mg/kg)	1.2 – 3.8	39 – 51
Copper (mg/kg)	86 - 98	24 – 38	Vanadium (mg/kg)	14 – 28	46 – 99
Iron (mg/kg)	1600 – 24,800	0.002 – 27,000	Zinc (mg/kg)	35 – 1211	126 – 235

Although cadmium and mercury are used as surrogate parameters for other trace metals, barium may be the most useful tracer for estimating the distribution of drilling fluids in bottom sediments (EPA 1982). Because aluminum is rarely introduced into the environment by anthropogenic activities, normalizing concentrations of other metals to those of aluminum can also provide a valuable tool for identification of potential sources related to barite sediment. In general, heavy metals within drilling fluids have a very limited bioavailability to marine animals due to their insolubility (EPA 1982). However, if mercury is reduced to methyl mercury in deep sediment deposits, it can become bioavailable to marine animals (Neff 2010). Trefry and Smith (2003) have examined the relationship between barite concentrations in sediments near drilling platforms in the Gulf of Mexico and the methyl mercury concentrations

in sediments and concluded there was no relationship. Results from Trefry and Smith (2003) suggest that mercury concentrations in barite are not toxic to marine organisms, as transformation to methyl mercury was not observed.

Lubricants are added to the drilling fluid when high torque conditions are encountered on the drill string. These can be vegetable-, paraffinic-, or asphaltic-based compounds such as Soltex.

Spotting agents are used to help free stuck drill strings. A concentrated slug or "pill" of the spotting agent is pumped downhole and up the annular space between the borehole and drill pipe. After working to free the stuck pipe the pill is then pumped back to the surface. Some of these agents are easily broken down in the environment (e.g., vegetable oil or fatty acid glycerol). Although effective at unsticking pipe, diesel is not allowed by the ELGs nor authorized for use. The most effective and frequently used spotting agents are mineral oil-based. Data shows that the concentration of organic pollutants in the drilling fluids is roughly proportional to the amount of mineral oil added. Mineral oils from pills, if not properly managed, can contribute potentially toxic organic pollutants to drilling fluids. Residual amounts of mineral oil pills may occasionally be discharged during drilling. However, standard operating procedures require certain precautionary measures to be taken to minimize contamination of the drilling fluids.

4.1.3 Drilling Fluid Toxicity Characteristics

Because metals in barite typically exist as inclusions of insoluble metal salts, limits based on dissolved water quality criteria are not practicable. Industry practice relies on suspended phase particulate (SPP) toxicity estimates or test results to characterize a specific drilling fluid formulation. An SPP toxicity test (EPA Method 1619) determines the 50 % lethal concentration (LC_{50}) of drilling fluids and additives in a 96-hour toxicity test. Per 40 CFR 435, a concentration of 30,000 parts per million (ppm) by volume (3 % solution) or less is considered to be toxic and cannot be authorized to be discharged under any circumstance. An LC_{50} greater than 100 % (1,000,000 ppm) indicates that drilling fluid mixture did not result in 50 % mortality during the SPP test. Note that even these non-toxic drilling fluids require an APDES permit if discharged due to their meeting the definition of a point source under the CWA and other potential water quality concerns (e.g., high turbidity, zones of deposits, etc…). The toxicity level and the volume of fluids proposed to be discharged are not the only factors used to determine the level of pollution control required by a permit.

4.1.4 Tiered Drilling Fluid Classification System

The tiered drilling fluid classification system is based, in part, on the Oslo and Paris (OSPAR) Commission's List of Substances Used and Discharged Offshore which are considered to Pose Little or No Risk to the Environment PLONOR (OSPAR 2013) list and generic drilling fluid toxicity results from EPA (1984). Use of more toxic additives is connected to more stringent limitations or additional environmental monitoring requirements.

Typically, the non-oil and gas drilling activities occur in the shallow subsurface regions that typically encounter predictable uncomplicated geology that are amenable to using uncomplicated, low toxicity fluid systems. For this reason, the Department divides drilling fluid characterization into two categories for the Permit: Class C Drilling Fluids used for shallow non-oil and gas activities discharging to marine water, and Class B Drilling Fluids used for deeper oil and gas activities that can have complicated, moderate to high toxicity fluids systems. Note that Class A Drilling Fluids are similar to Class C except are discharged to freshwater. The Department considers only Class B Drilling Fluids as applicable to oil and gas standards and regulations (e.g., 40 CFR 435). However, some of these oil and gas standards and regulations can be used to classify non-oil and gas drilling fluid systems. As near shore environments can be more sensitive to drilling fluid discharges, DEC has developed a tiered approach that accounts for this sensitivity in relation to permit limitations and DFP and EMP

Plan requirements. The drilling fluids systems that pose the most risk have more stringent requirements when discharging to sensitive areas.

4.1.4.1 Class B Drilling Fluids

Fluids are considered to be Class B fluids if they are directly related to oil and gas exploration or development drilling activities and regulated under 40 CFR 435. Some fluids are simplistic and consist of manufactured clays or polymers that have low toxicity and metals concentrations. Sometimes, drilling the top portions of oil and gas wells use fluids such as these. For deeper or more complicated geologic formations, drilling programs may need to use more complicated drilling fluids systems with numerous additives, such as weighting agents (e.g., barite) or lignosulfates that have metals concentrations or higher toxicity, respectively.

4.1.4.2 Type C Drilling Fluids

Class C Drilling Fluids are generally clay-based fluids used for ancillary activities including, but not limited to, geotechnical drilling operations or HDD associated with pipeline construction and installation. The clay-based drilling fluids consist mostly of water, bentonite, and trace amounts of additives. Typical additives include natural and modified polymers such as starches, cellulose, and zanthium to modify viscosity or soda ash and other chemicals to adjust pH. If HDD is through complex geology, additives could include several commonly used in oil and gas drilling. Furthermore, the need to protect against blowouts from shallow gas pockets or artesian aquifers may lead to the use of barite for drilling fluids. Table 4 provides a summary of the tiered drilling fluid classification system used in the Permit.

Table 4: Drilling Fluid Classifications System

Use and Classification		Fluid Characteristics per Classification			
Use	**Class [1]**	**SPP LC_{50} (ppm) [2]**	**Base Fluid (Water or Synthetic)**	**Number of Ingredients [3]**	**Barite (Yes/No)**
Oil and Gas	B1	≥ 750,000	Water	≤ 2	No
	B2	> 30,000	Water	> 2	Yes
	B3	> 30,000	Synthetic	> 2	Yes
Ancillary	C1	≥ 750,000	Water	≤ 2	No
	C2	> 500,000	Water	> 2	No
	C3	> 500,000	Water	> 2	Yes

Notes:
1. Class A fluids are for discharges to freshwater and are not included in the Table because the Permit authorizes only marine discharges to Cook Inlet.
2. Compliance with SPP LC_{50} toxicity must be analyzed for all Class B fluids and C3 fluids. Class C1 and C2 fluids may be estimated or analyzed to demonstrate compliance with classifications.
3. Freshwater or seawater (water) is not counted as an ingredient.

4.1.5 Drilling Fluid Discharge Volumes

During drilling, fluids are pumped downhole and circulated back to the surface carrying rock fragments that are separated from the drilling fluid so the fluid can be reused to the extent feasible. The operator may need to discharge drilling fluids under a variety of circumstances, including fouling of the drilling fluid over time, significant changes to the fluid mixture, change in drilling phases, and well completion/closure. When drilling is completed, facilities typically discharge the remaining drilling fluids in bulk. During HDD Projects for onshore to marine transition for pipelines, the drilling fluids are typically discharged when the borehole daylights to the marine water at the seafloor. For geotechnical surveys using rotary with risers, the discharge results when the riser pipe leaves the borehole and the remaining drilling fluids inside

the riser are discharged to the surrounding receiving water. Another important factor governing the need to discharge fluids is the constraint of solids storage (slurry tanks) at the facility that may not be sufficient to store and reuse all drilling fluids throughout the drilling process.

DEC has reviewed approximately 20 years of historic well data from Cook Inlet and elsewhere and recently available information to update preliminary estimates of discharge quantities of drilling fluids and drill cuttings for oil and gas and HDD and geotechnical drilling projects. DEC has compared recent data with historic data and has concluded that estimating volumes of drilling fluids and drill cuttings accurately is challenging, given the variables involved. Estimates based on project-specific information is the best approach. Table 5 provides an estimate of the average per well and maximum expected volumes of drilling fluids and drill cuttings based on available information.

Table 5: Estimated Discharge Volumes per Well

Discharge Description	Average (bbls/well)	Maximum Volumes (bbls)
Oil and Gas Drill Cuttings	4,500 bbls/well	153,000 bbls [1]
Oil and Gas Drilling Fluids	11,200 bbls/well	381,000 bbls [2]
Geotechnical Survey Fluids and Cuttings	2 bbls/boring	250 bbls [3]
HDD Drilling Fluids and Cuttings	31,845 bbls/Project [4]	127,500 bbls [5]
Estimated Maximum Volumes of Drilling Fluids and Drill Cuttings		**661,750 bbls**

Notes:
1. Volumes are estimated on the depth of well, conversion factors, and data when available. Maximum volumes are based on 20 wells for exploration and 14 wells for production.
2. Values based on End of Well Reports, DMRs, and accounts for 20 wells for exploration and 14 wells for production to be drilled over the permit cycle.
3. Value includes 25 borings per year of the Permit.
4. Value is based on Furie's HDD Project.
5. Maximum volume is based on four projects during the term of the Permit.

4.2 Deck Drainage (002)

Deck drainage originates from rain and snowmelt events that can come into contact with contaminates and transport debris or oil and grease into receiving waters. The discharge is considered applicable to all offshore platforms, geotechnical or HDD facilities, and some shore-based facilities (including marine terminals), regardless of operational capacity, and construction support activities.

Deck drainage refers to any wastewater generated from platform washing, deck washing, spillage, rainwater, and runoff from curbs, gutters, and drains, including drip pans and wash areas. Since the discharge of deck drainage is intermittent and dependent on precipitation, volumes can vary widely from 1,000 to 25,000 gpd. Maximum daily flow estimates are provided in Table 6. Oil and grease are the primary pollutants identified in the deck drainage waste stream. Untreated deck drainage can contain oil and grease in quantities ranging from 12 to 1,310 mg/L (DEC 2015). In addition to oil, various other chemicals used in drilling operations could be present in deck drainage. These chemicals include drilling fluids additives, ethylene glycol, lubricants, fuels, biocides, surfactants, detergents, corrosion inhibitors, cleaners, solvents, paint cleaners, bleach, dispersants, coagulants, and any other chemical used in the daily operations of the facility. Effective BMPs are typically used to prevent or minimize the inclusion of these chemicals in deck drainage discharges.

On average, drilling from a MODU has been reported to take approximately 50 days per well. However, the total time at the site may be as long as 90 days or more. This extended time period on site is due to prior to and post drilling activities, weather and supply boat delays, and required

downtime to perform required equipment testing and maintenance. To estimate volumes for incidental, non-drilling discharges, DEC assumes a rig will be on site a total of 90 days per well.

Table 6: Effluent Characteristics for Deck Drainage

Type of Facility	Estimated Flow
Estimated Maximum Daily Flow – Platform	2,000 gpd
Estimated Maximum Daily Flow – Seasonal MODU	1,000 gpd
Estimated Maximum Daily Flow –Construction Support Facility	750 to 1750 gpd

4.3 Domestic Wastewater (003)

While some platforms discharge treated domestic wastewater originating just from toilets and urinals (black water), some combine graywater, or portions of graywater, with black water prior to treatment and discharge. This section provides characterization of either of these scenarios. Whereas, Section 4.4 provides characterization of discharges of just graywater alone. See previous Section 3.5.4.1 that provides further clarification and discussion on domestic wastewater.

Existing practices in Cook Inlet generally indicate that domestic wastewater and graywater is either injected downhole or discharged via the disposal caisson. Typical volumes for domestic wastewater and graywater can range from approximately 1,500 gpd to 7,000 gpd. Pollutants of concern in domestic wastewater include BOD_5, TSS, fecal coliform (FC) and enterococci (EC) bacteria, and TRC. Note that per 40 CFR 435, FC and EC bacteria are controlled effectively through the ELG establishing a minimum TRC level of 1 mg/L at the point of chlorination. The 2007 GP and other permits described in Section 3.4 also established facility-specific WQBEL for TRC prior to discharge. Most of the domestic treatment systems include a dechlorination step; dechlorination is common, readily available treatment option for MSDs. In addition, the 2007 GP established categories of domestic wastewater treatment systems in order to develop attainable limits for BOD_5 and TSS for certain systems that could not achieve secondary treatment standards. The following provides information and definitions necessary for understanding how domestic wastewater is characterized in this section:

- A Type I MSD refers to an onboard sewage treatment system that uses a physical and chemical process consisting of maceration and chlorination for destruction of BOD_5 and TSS.
- A Type II MSD or MSD or MSD/BTU are used to destroy BOD_5 and TSS.
- BTUs without the MSD descriptor refer to a biological system that is not part of an MSD. Dechlorination is a common add-on feature for these types of treatment systems and the Department requires dechlorination as a technology-based requirement to reduce TRC concentrations prior to discharge.

In addition to the above treatment systems designations, the following two definitions from the ELGs provide information about how the facility is occupied:

- The M10 designation refers to an offshore facility that is continuously manned by 10 or more persons and treats domestic wastewater using an MSD.
- The M9IM designation refers to an offshore facility that is continuous manned by nine or fewer persons or intermittently manned by any number of persons.

The issuance of the 2007 GP established limits using observed performance data for various categories of treatment system types and staffing levels. Essentially, BTUs are not able to meet secondary treatment standards for BOD_5 when staffing is intermittent or less than 9 persons (See Section 3.5.4.2). In addition, only BTUs with continuous staffing of 10 or more persons can

attain secondary treatment standards for TSS. Table 7 provides a summary of applicable limits based on staffing and treatment systems.

Table 7: Domestic Wastewater (Discharge 003) Existing Limits

Staffing	Treatment System	BOD_5		TSS	
		MDL	AML	MDL	AML
M9IM	MSD & MSD/BTU	60	30	67	51
	BTU	90	48	108	56
M10	MSD & MSD/BTU	60	30	67	51
	BTU	60	30	60	30

A summary of the existing treatment systems is shown in Table 8 on the next page.

Table 8: Summary of Existing Domestic Wastewater Systems

Platform	Staff, Type[1]	Waiver Approved	Design Flow (gpd)[2]	Observed Flows (gpd) Min – Max; Average
Bruce [1]	M9IM, BTU	Yes [2]	3,975	480 - 2,940; 1,167
GPP [1]	M10, MSD	No	21,600	5,700 - 22,916; 13,687
Tyonek A [1]	M10, BTU	No	3,975	900 - 5,100; 2,368
Julius R [1]	M10, MSD/BTU	--	2,000	32.5-780; 266
Dillon [1, 3]	M9IM, BTU	Yes [2]	4,350	1,227 - 2,924; 2,281
Baker [4]	M9IM, BTU	Yes [2]	4,650	654 -2,503; 1,430
Anna [5]	M9IM, MSD	Yes [2]	5,400	--
King Salmon [5]	M10, MSD	No	5,550	--
Dolly Varden [5]	M10, MSD	No	4,575	--
MGS A [5]	M10, MSD	No	5,000	--
MGS C [5]	M10, MSD	No	5,000	--
Grayling [5]	M10, MSD	No	5,025	--
Monopod [5]	M10, MSD	No	4,575	--
Steelhead [5]	M10, MSD	No	5,925	--
Osprey [6, 7]	M9IM, MSD/BTU	No	6,600	--
Spartan 151 [4, 7]	M10, MSD/BTU	No	Pending	--
Yost [8]	M10, MSD/BTU	--	7,500	8,493 – 4479; 14,374

Notes:
1. Currently treats domestic wastewater and discharges on a routine basis during normal operations.
2. Waiver to minimum treatment granted through the CWA 401 Certification of the 1999 GP.
3. Currently out of service but could be operational during permit term.
4. Currently hauls domestic wastewater to shore but may discharge during the term of the permit term.
5. Currently injects domestic wastewater but requires an authorization for contingency to well shut-in.
6. Currently injects domestic wastewater and plans to haul to shore as a contingency to well shut-in.
7. Can obtain coverage for discharging upon receiving approvals under 18 AAC 72.
8. Although approvals provided by DEC under 18 AAC 72, facility has not complied with limits.

Of the 16 existing platforms and two MODUs, seven have discharged domestic waste during the period of reviewed allowing for characterizing their respective discharges. Of those seven, the Julius R Platform and Randolph Yost MODU are combining all of the graywater and black water sources for treatment and discharging under Discharge 003. The Spartan 151 MODU and Baker are currently hauling domestic wastewater to shore. The remaining existing platforms treat domestic wastewater and inject the effluent into wells and, as a result, do not have current characterization data. These platforms desire to retain authorizations to discharge as a contingency to a UIC well shut-in. Whereas, the Osprey Platform proposes to haul domestic wastewater to shore as a contingency to a UIC well shut-in. For those eight facilities that have

discharged routinely as part of normal operations for the period of review, Table 9 provides a summary of the characteristics based on review of discharge monitoring reports (DMRs) and comparison with specific maximum TRC limits and applicable limits for BOD_5 and TSS from Table 7 applied to the staffing level and system in from Table 8.

Table 9: Domestic Wastewater Discharges (Discharge 003) Characterization

Platform or MODU	Parameter (Units) [1]					
	TRC (mg/L)		BOD_5 (mg/L)		TSS (mg/L)	
	Limit	Min – Max; Ave	MDL/AML	Min – Max; Ave	MDL/AML	Min – Max; Ave
Baker [2]	2.25	0.8 – 0.98; 0.9	90/48	2.0 – 21; 11.6	108/56	0.3 – 3.9; 1.6
Dillon [2]	0.66	0.02 – 0.24; 0.1	90/48	3.0 – **51**; 19.8	108/56	3.0 – 8; 5.0
Bruce	2.25	0.02 – 1.1; 0.16	90/48	2 – **50**; 9.8	108/56	0.4 – **180**; 12.9
GPP	7.68	0.01 – 4.0; 1.66	60/30	2 – **187**; 21.3	67/51	2 – **126**; 23.1
Tyonek A	13.35	2.6 – 12.8; 7.48	60/30	2.9 – **53.8**: 13.4	60/30	1.0 – **66.5**; 8.66
Julius R [3]	1.0	0.2 – 1.0; 0.94	60/30	2.8 – 23.8; 9.01	60/30	1.09 – 23.5; 7.73
Yost [3, 4]	1.0	1.0 – **3.4; 2.8**	60/30	11.4 – **402; 180**	60/30	**54 – 720; 184**

Notes:
1. Observed values that exceed limits are shown as bold.
2. Characterization is based on a data set of four sample events.
3. The Julius R Gas Production Platform and Randolph Yost MODU combine graywater for treatment and disposal.
4. Discharges for Randolph Yost are from the Julius R Gas Production Platform while the Yost was conducting drilling for additional gas wells under AK0053686.

New domestic wastewater treatment systems were recently installed on Julius R Gas Production Platform and the Randolph Yost. The Julius R treatment system experienced difficulties in meeting discharge limits during the startup period, approximately three months. This data was excluded from the characterization. The Randolph Yost also experienced difficulties during start up related to a series of equipment and power issues affecting chlorine generation and solids handling that could not be commissioned out of the system during the five months of startup and operation. During this period, the permittee contracted with the equipment vendor and conducted additional sampling to troubleshoot the problem. Although the data is not representative of a fully functioning system, it is being provided until new representative data can be obtained from a fully functioning treatment system.

4.4 Graywater (004)

Graywater includes wastewater from kitchens, showers, and laundry facilities and the parameters of concern are BOD_5, TSS, and floating materials including solids, foam, garbage and oily sheens. Table 10 provides an overview of the different types of facilities and related flows.

Table 10: Graywater (Discharge 004) Flow Summary

Facility Type [1]	Flows (gpd) Min – Max; Ave
Fixed Platforms	650 - 4,200; 2,425
Spartan 151	1,944 – 3565; 2951

In most of the facilities in Cook Inlet, graywater is piped separately from domestic wastewater and there is often several discharge points on a single platform or MODU. A few platforms report that all or portions of graywater are included in the domestic wastewater systems either before or after treatment. For example, the GPP commingles all graywater after the domestic wastewater treatment and discharges the combined effluent through a discharge port. DEC believes such discharge practices are appropriate and consistent with the intent of 18 AAC 72. However, this appears to be an exception rather than normal operations on platforms. As discussed previously in Section 3.5.4.1, graywater is considered domestic wastewater and held to

the same minimum treatment requirements, unless a waiver for secondary treatment is requested and approved per 18 AAC 72. A prerequisite for obtaining a waiver is by meeting primary treatment, defined as a 30% reduction in the BOD_5 and TSS. Due to the historic perspectives discussed previously, waivers have not been requested or approved for most discharges of graywater. Removing 30 % of BOD_5 or TSS in in graywater can be difficult given the presumed low influent concentrations and characterization data that can be used to demonstrate this requirement is not commonly collected. In addition, the discontinuous discharge piping of graywater is difficult to plumb for a single point of treatment and discharge. However, the Spartan 151 MODU obtained and submitted data where graywater was treated using an MSD. Based on submittal of information, the Spartan 151 was able to obtain a waiver and get authorization to discharge graywater under AKG315100. Table 11 provides characterization of the influent, effluent, and percent removal from seven samples collected by Spartan 151 in 2015 to support the request of a waiver to minimum treatment.

Table 11: Graywater Characteristics from Spartan 151 Waiver Request

Parameter [1]	Influent (mg/L)	Effluent (mg/L)	Percent Removal (%)
	Min – Max; Ave	Min – Max; Ave	Min – Max; Ave
BOD_5	206 – 758; 430	28.9 – 223; 162	13.6 – 88.9; 58.2
TSS	56.0 – 373; 139.8	16.5 – 3.9; 10.7	75.7 – 99.0; 88.4
TRC	1.24 – 3.6; 2.1	0.27 – 1.1; 0.52	69.4 – 82.6; 76.5

Notes:
1. For flow data associated with the waiver Request see Spartan 151 in Table 10.

4.5 Miscellaneous Discharges (005-014)

Multiple discharges are categorized as miscellaneous due to their variable, typically low flows, and use of chemical additives. These discharges may be either seawater or freshwater. Permittees use a broad range of chemicals to treat seawater and freshwater in offshore operations. The most common types of chemicals include biocides or bactericides, oxygen scavengers, scale and corrosion inhibitors, coagulants, defoaming agents and dispersants. Table 12 provides a summary of average and maximum estimated total discharge volumes (over the five-year term of the Permit) for the miscellaneous discharges including Desalination Unit Wastes (005) through Drilling Fluid, Cuttings, and Cement at the Seafloor (013) (DEC 2015).

Table 12: Estimated Miscellaneous Fluids (005-013) Discharged Volumes Per Well

Discharge Description (Number)	Average Facility Discharge (bbls)	Total Estimated Discharges (bbls)
Desalination Brine (005)	18,000	360,000
BOP Fluid (006)	90	1,800
Boiler Blowdown (007)	360	7,200
Fire Control Test Water (008)	200,000	4 MM
Noncontact Cooling Water (009)	450,000	9 MM
Ballast water (010)	150,000	3 MM
Bilge Water (011)	180	3,600
Excess Cement (012)	350	70,000
Fluids, Cement and Cuttings at Seafloor (013)	500	10,000

Additional details regarding each discharge are included in the following sections.

4.5.1 Desalination Unit Wastes (Discharge 005)

Desalination unit waste is typically residual high-concentration brine, associated with creating freshwater from seawater via distillation or reverse osmosis (RO) processes. It can also include backwash from sand filters used to pretreat and condition seawater prior to desalination. Similar to waterflooding (Discharge 014), backwash from sand filters for drinking water may include biocides that help prevent bacterial growth in the sand filter. The concentrate from the desalination process is similar to seawater in chemical composition, with higher anion and cation concentrations. If RO is used, the discharge could include chemical additives to enhance flux rates and scale inhibitors. Discharges from desalination units typically occur via the disposal caisson and may vary greatly in volume and frequency depending on the treatment system and the freshwater needs of the rig (human consumption or other applications). The reported volumes range from 3,700 gpd to 20,000 gpd (DEC 2015). Due to the potential of discharging greater than 10,000 gpd with chemicals, desalination is included in the chronic WET monitoring requirements for miscellaneous discharges.

4.5.2 Blowout Preventer Fluid (Discharge 006)

A blowout preventer (BOP) is a device typically located below the seafloor designed to maintain the pressure in the well that cannot be controlled by other means, such as with drilling fluid. Fluid designed to operate with the blowout preventer may be discharged in small quantities (less than 42 bbl/well (1,684 gal/well) or approximately 7 bbl (294 gal) per testing event) when the blowout preventer is actuated on the hydraulic equipment. The design of the blowout preventer is such that the fluid used to open it after it has been closed for testing must be forced through the system and discharged into surrounding receiving water at the unit itself (newer units can discharge into the annulus between the drill pipe and borehole). Testing of the blowout preventer device must be conducted periodically (typically on a weekly basis), resulting in intermittent discharges. Drill rigs operating in Cook Inlet routinely test BOP equipment biweekly in accordance with American Petroleum Institute (API) Recommended Practice No. 53 and Alaska Oil and Gas Conservation Commission (AOGCC) requirements. The primary constituents of blowout preventer fluid are oil (vegetable or mineral) or seawater mixed with an antifreeze solution (ethylene glycol) (DEC 2015).

4.5.3 Boiler Blowdown (Discharge 007)

Boiler Blowdown discharges vary from approximately 100 to 200 gpd. Boiler blowdown is the discharge of water and concentrated minerals in order to minimize solids buildup created by heating and consequent evaporation of water inside boiler drums. Boiler blowdown is a low volume, intermittent discharge of freshwater from a closed boiler system. After discharge of blowdown, fresh water is added to help maintain water quality characteristics in the closed system (DEC 2015).

4.5.4 Fire Control Test Water (Discharge 008)

Fire control system test water is typically seawater discharged during training events and the testing and maintenance of the fire protection equipment on a platform, or in response to a fire at a facility. Fire control system test water discharges occur as an overboard discharge. This test water may be treated with a biocide or corrosion inhibitor. When additives are not used, discharge volumes can be up to 1,500,000 gpd per discharge event from MODUs. This volume is typically an order of magnitude less if chemicals are used (DEC 2015). The typical range of discharges from existing platforms and MODU's is 3,000 to 200,000 gpd and is generally intermittently discharged.

4.5.5 Noncontact Cooling Water (Discharge 009)

Noncontact cooling water is seawater used for noncontact, once-through cooling of various pieces of machinery at the facility (e.g., power generators). The volume and discharge

temperature of noncontact cooling water depends on the configuration of heat exchange systems on the MODU or fixed platform and range from 250 to 3,600,000 gpd for existing platforms. Some systems use smaller volumes of water that are heated to a greater extent, resulting in a higher temperature differential between waste water and receiving water. Noncontact cooling water has the potential to be 2 - 45 °C (3.6-81 °F) warmer than the receiving water, which is generally at 0 - 1 °C (32-34 °F). Existing platforms discharge temperatures were reported as 14.8 - 23 °C (58.6-73.4 °F) in recent applications. Discharges occur via numerous overboard outfall configurations generally classified as surface or submerged discharges.

During development of the Permit, DEC conducted facility-specific analyses of current chemical use and discharge rates applicable to noncontact cooling water. The objective of these analyses was to address stakeholder concerns requesting a better understanding of chemicals being discharged to Cook Inlet (See Section 2.3.1). Accordingly, DEC requested a listing of potential chemical additives in these discharges, dosing practices and volumes, and submittal of SDSs in order to estimate the potential chronic toxicity. In addition, DEC focused on chronic WET characterization on those facilities that routinely discharge greater than 10,000 gpd and include chemical additives, either added directly or as a consequence of piping interconnections with other source such as waterflooding side streams. Facilities meeting this criteria were required to conduct chronic WET monitoring to characterize chronic toxicity. DEC concluded that currently, the platforms MGS – A and MGS – C meet this criteria and have appropriately conducted chronic WET monitoring under the 2007 GP.

Based on the information provided, the list of chemical additives included chlorine-based bactericides, coagulants, and dispersants. Although the estimates of chronic toxicity estimated through desktop analysis of discharge rates and dosing practices indicated potential for spikes of high chronic toxicity associated with the use of chlorine, none of the seven chronic WET monitoring tests results from 2012 to present have comparable toxicity. All seven WET tests did not result in observable endpoints in the highest concentration dilutions tested, suggesting there is no chronic toxicity present in the effluent. Alternatively, it may also be that the logistic of collecting representative samples reflecting spikes from the batch dosing practices is not currently practicable. More discussions on this issue is provided in Section 4.5.10.

4.5.6 Uncontaminated Ballast Water (Discharge 010)

Ballast water is seawater that is taken into the hull of a vessel for stability. In the case of MODUs, ballast water is seawater added or removed to maintain the proper ballast and ship draft for stabilization while the MODU is in transit. Ballast water is also discharged to set the legs of jackup rigs on the seafloor, which happens intermittently a few times during an active drilling season. Recent information indicates the volume can be 1,500,000 gallons per each positioning effort at a well location (DEC 2015). Historically, ballast water was often combined with other vessel wastewater but this is not the case in newer MODUs. Uncontaminated ballast water is seawater that has been taken into a MODU and has not be comingled with deck drainage or other wastes. If contaminated with oil, the ballast water must be treated using an oil-water separator (OWS) or other oil removing process prior to being discharged.

4.5.7 Bilge Water (Discharge 011)

Bilge water is seawater that collects in the lower, internal parts of the MODU and often becomes contaminated with oil, grease and solids such as rust when it collects at low points in the bilges. Volumes are typically low, but may be up to 7,900 gpd and are discharged intermittently (DEC 2015). Similar to contaminated ballast water, bilge water must be treated using an OWS or other oil removing process prior to discharge.

4.5.8 Excess Cement Slurry (Discharge 012)

The discharge of excess cement slurry at the seafloor surface will result from equipment washdown after cementing operations during drill casing installation. The volumes vary based on drilling conditions and the casing and testing program in effect. Typical volumes range between 5,500 gpd to 55,500 gpd. There may be approximately four intermittent discharge events, or more, of excess cement slurry during well installation (DEC 2015).

4.5.9 Drilling Fluid, Cuttings, and Cement at the Seafloor (Discharge 013)

Drilling fluid, cuttings, and cement are materials discharged at the seafloor during various phases of drilling operations, including include spudding, re-entering an abandoned, shutting-in, or plugging a well, or during cementing operations before casing is set for plugging and abandoning, or shutting-in wells. This discharge also results from disconnecting the marine riser on drill ships and semisubmersibles. Aside from cement, cement extenders, accelerators, and dispersants are the main chemicals added to this discharge. Reported volumes in Cook Inlet are approximately 3,500 gpd when discharges occur but other sources indicate up to 175,000 gpd (DEC 2015).

4.5.10 Waterflooding Wastewater Chronic Toxicity (Discharge 014)

Many platforms inject treated seawater into producing formations to enhance hydrocarbon recovery rates. In most cases, the seawater goes through a treatment process, including filtration. Waterflooding wastewater refers to the filter backwash water that is used periodically to clean the seawater treatment filters. The waste stream consists primarily of salts, sediment, trace elements and chemical additives. Chemical additions commonly include biocides (primarily chlorine but some aldehydes) but could be cross-contaminated with oxygen scavengers, scale and corrosion inhibitors, coagulants, clarifiers, defoaming agents and dispersants. Waterflooding wastewater discharges occur at existing fixed production platforms but not exploration MODUs. They are generally continuous in nature, but chemical additives are commonly added in batches once or twice a week. Discharge volumes range in volume from 100,000 to 5,000,000 gpd.

Due to the intermittent use of unspecified chemical additives, chronic WET monitoring was included in the 2007 GP to characterize waterflooding discharges. Although appropriate for the purpose of characterizing effluent containing unspecified chemical additives, the chronic WET monitoring approach has not yielded, with one exception for GPP, results where toxicity endpoints have been observed in the highest dilution concentrations tested. Similar to noncontact cooling water, DEC requested chemical lists, SDSs, and dosing practices in order to conduct a desktop estimate of potential chronic toxicity in the effluent. In addition, DEC requested that the chronic WET monitoring dilution series used in tests be expanded to cover a broader range of potential toxicity rather than the dilution series specified in the 2007 GP that was designed to bracket triggers for accelerated testing. Facility flow rates, chronic WET monitoring results obtained from 2012 through 2016, chronic toxicity triggers from the 2007 GP, and revised desktop chronic toxicity estimates for waterflooding discharges are summarized in Table 13.

Table 13: Waterflooding Wastewater (014) Characterization

Facility	Flow (mgd)	Data Set	Recent (TU_c)	2007 Trigger (TU_c)	Est. Toxicity (TU_c)
King Salmon	0.550	10	<1.43	7.3	85
Dolly Varden	5.209	12	<1.43	18.2	95
Platform A	0.132	10	<1.43	N/A	706
Platform C	0.132	10	<1.43	N/A	1084
GPP	0.17	10	**1.87**	14	32
Grayling	5.14	10	<1.43	16.3	37
Monopod	2.32	10	<1.43	17.1	90
Steelhead	0.903	10	<1.43	604	85

In all cases except one chronic WET result for GPP, all reported values indicate no chronic toxicity because chronic toxicity endpoints were not observed in the highest concentration dilution tested. However, given that chemical applications are typically applied in batches and each facility may have a different response to batch dosing affecting the timing and duration of spikes of toxicity in the discharge there remains a question as to the practicality of collecting a sample that represents the maximum toxicity. In addition, if it is not practicable to monitor chronic WET to characterize or control toxicity in the effluent, then a different approach may be appropriate. Important to this discussion is acknowledgment that exposure to aquatic life, frequency and duration, from discharges that are intermittently dosed with chemical additives in desalination waste, waterflooding, or noncontact cooling water is less than the exposure for which chronic aquatic life criteria are developed. For example, dosing at a frequency of twice a week results in approximately one hour of potential exposure to aquatic organisms twice per week. Compared to a four-day continuous exposure period for which chronic aquatic life criteria are derived there would be little toxic response when considering the duration of exposure followed by a lengthy recovery period after each dosing. Hence, the current practices are not likely to have resulted in significant effects on aquatic life. Nonetheless, the overarching goal should be to reduce pollutants discharged when and where practicable.

4.6 Produced Water (Discharge 015)

4.6.1 Produced Water Composition

Produced water often is generated during the production of oil and gas from onshore and offshore wells. Gas wells tend to produce less produced water than oil wells. Formation water is seawater or fresh water that has been trapped for millions of years with oil and natural gas in a geologic reservoir consisting of a porous sedimentary rock formation between layers of impermeable rock within the earth crust (Collins, 1975). When a hydrocarbon reservoir is penetrated by a well, the produced fluids may contain this formation water, in addition to the oil, natural gas, gas liquids, and waterflood injected into the formation for enhanced oil recovery. Fresh water, brine/seawater, and production chemicals sometimes are injected into a reservoir to enhance both recovery rates and the safety of operations and these surface waters and chemicals sometimes penetrate to the production zone and are recovered with oil and gas during production. Produced water (formation and injected water containing production chemicals) represents the largest volume waste stream in oil and gas production operations on most offshore platforms. Produced water may account for 80% of the wastes and residuals produced from natural gas production operations (Neff, 2011).

Produced water is a complex mixture of dissolved and particulate organic and inorganic chemicals. Common parameters of concern include ammonia (as Nitrogen), total aromatic hydrocarbons (TAH), total aqueous hydrocarbons (TAqH), and various metals. The physical and chemical properties of produced water vary widely depending on the geologic age, depth,

and geochemistry of the hydrocarbon bearing formation, as well as the chemical composition of the oil and gas phases in the reservoir, and production chemical additions.

4.6.2 Produced Water Treatment

Oil is generally produced in emulsion with water and must be separated. There are various technologies used in tandem to separate oil and gas from the produced water to the level required to discharge to Cook Inlet. An incomprehensive list is provided below:

- Equalization (e.g., surge tanks and skim tanks)
- Chemical Addition (e.g., surfactants, coagulants, polyelectrolytes)
- Flotation (e.g., dissolved gas or induced)
- Filters
- Oil and/or Solids Removal
- Gravity Separators
- Plate Coalescers
- Subsurface Injection

Although existing OWSs, such as hydrocyclones, can efficiently remove oil droplets they are not efficient in removing dissolved hydrocarbons, organic acids, phenols, and metals from produced water. The ELGs for produced water discharges are based, in part, on implementation improved gas flotation treatment. Much of the petroleum hydrocarbons discharged to Cook Inlet from appropriate produced water treatment systems are dissolved, low molecular weight aromatic hydrocarbons and smaller amounts of saturated hydrocarbons. Because there are no practicable treatment processes that are 100% effective, treated produced water still contains some dispersed oil (droplet size ranging from 1 to 10 micrometers). These droplets contain most of the higher molecular weight, less soluble saturated and aromatic hydrocarbons (Neff, 2011). Table 14 provides an overview of general produced water characteristics after treatment on a global perspective as well Cook Inlet specific.

Table 14: General Produced Water Characteristics After Treatment

Parameters (Units)	Global [1]	Table VIII-4 [2]	Table VII-5 [3]	Cook Inlet Observed Range[4]
Ammonia (as N) (mg/L)	85	41.9	--	1.45 - 15.4
Oil and Grease (mg/L)	--	26.6--	35.4	1.53 - 81.35
Manganese (µg/L)	--	1,680-	4915.87	1.32 - 2.7
Copper (µg/L)	0.03 - 137	236	444.66	3.2 - 33
Mercury (µg/L)	0.00007 - 10	--	--	0.212 - 1.69
Silver (µg/L)	--	359	--	0.729 - 10.1
Zinc (µg/L)	0.006 – 26,000	462	1,705.46	0.98 - 39.8
TAH (µg/L)	680 - 578,000	9,877	5,594	4,000 - 30,000
TAqH (µg/L)	40 – 2,148	18,863	7,569	3,405 - 19,613

Notes:
1. Neff, Produced Water (2011)
2. Coastal Subcategory of the Oil and Gas Extraction Point Source Category Development Document. Summary of analytical data from settling tank effluent, EPA 1992.
3. Coastal Subcategory of the Oil and Gas Extraction Point Source Category Development Document. Summary of analytical data representative of produced water in Cook Inlet
4. DMR data from 2008-2015
5. All metals are reported as total recoverable except for mercury, which is reported as total.

The data provided in the global summary (Neff, 2011) does not account for treatment technology other than those typical for the respective region. The data from Table VIII-4 represents produced water treated using primarily settling tanks from multiple regions. Data from Table VIII-5 is representative of Cook Inlet and was based on samples analyzed by EPA to evaluate produced water to support development of the ELGs and also includes some Cook Inlet data used for Table VIII-4 and data provided by Alaska Oil and Gas Association. Finally, the observed range of characteristics represents compilation of all produced water discharges from Cook Inlet facilities obtained from DMRs representing the period of review from 2012 through 2015. In general, the observed concentrations during the period of review are lower than those from a global perspective or evaluated previously in Cook Inlet.

The Cook Inlet produced water treatment scheme is that of primarily centralizing treatment at onshore facilities that have appropriate treatment technology and economies of scale. This is both an environmentally favorable approach as well as an economic one; the more oil removed from produced water from higher efficiency onshore treatment facilities prior to discharge the better for the environment and oil production. Many of the platforms under the 2007 GP have authorizations to discharge as merely as a contingency for situations when onshore treatment may not be possible and, except for Tyonek A and Julius R platforms, typically use skim tanks that are not as efficient treatment as systems at onshore facilities. The Tyonek A uses gas flotation and typically injects but requests authorization to discharge produced water. Julius R, which produces a dry gas, transfers small volumes produced water to the Furie GPF that can be disposed offsite. Figure 2 provides a listing of various platforms and the associated centralized treatment facility, if applicable.

Figure 2: Platform and Onshore Facility Fluid Transfer Diagram

Several platforms currently inject produced water at the platform and are marked with a single asterisk (*) in Figure 2. Recently, HAK conducted a pilot project at the Dolly Varden that included treatment system upgrades, three-phase coalecser treatment and chemical additives to allow injection of over 0.5 mgd of produced water at the platform (**). Although implementing similar projects is possible in the future could lead to reduced discharges from TBPF, these projects will not lead to attaining zero discharge via injection of produced water in Cook Inlet due to formation pressure limitations. EPA previously rejected zero discharge for new sources because of uncertainties regarding the availability of geologic formations that would be suitable for injection of adequate volumes of produced water.

In Cook Inlet, only the production formation is generally available for injection and this can lead to over-pressurization of the formation, which increases potential for loss of well control and works against optimization of EOR. For existing onshore processing facilities, it is not technically possible to inject large volumes of produced water into underlying formations and piping to locations farther way was determined to be economically infeasible (EPA 1993). Although some produced water could be injected at some platforms other than the Dolly Varden, maintaining safe and optimal formation pressures must be considered. For these reasons, EPA either determined it is not technically possible or economically achievable in to attain zero discharge in Cook Inlet based on information reviewed during the promulgation of 40 CFR 435 Coastal Subcategory in 1996. After considering all information available at the time, EPA developed ELGs for produced water based on improved gas flotation being technically and economically achievable for Cook Inlet facilities and no platform has reportedly discontinued protection as a result of this decision. Consequentially, the Osprey Platform that has historically injected produced water at the platform is requesting authorization to discharge produced water due to many of these discussion points.

4.6.3 Produced Water Discharge Volumes

Table 15 provides a comparison between the requested total maximum discharge flows of produced water from the 2007 GP to those requested under the Permit and observed during the term of review.

Table 15: Flowrates for Produced Water Discharges

Facility	2007 GP (mgd)	Current Estimate (mgd)	Observed Range (Min – Max; Ave)
Anna	0.084	--	--
Baker	0.045	0.045	--
Bruce	0.025	0.025	--
Dillon	0.193	0.193	--
GPTF	0.193	0.193	0.00735 – 0.035; 0.0213
TBPF	8.4	8.4	0.805 – 5.7; 3.57
MGS Onshore	0.84	0.84	0.062 – 0.18; 0.135
Osprey	--	1.05	--
Tyonek	.031	.038	--
Total	9.78	10.75	--

The flowrates from the 2007 GP and those currently estimated during the term of the Permit are derived from the applications submitted by each respective permittee and are based on projected maximum discharges needed during the life of the facility. Comparing the estimated maximums discharge volumes from the 2007 GP to those currently estimated for the Permit, all previously estimated discharges either stayed the same or have been reduced, except for Tyonek A. In addition, the discharge from the Anna Platform has been eliminated from the current estimate and the proposed discharge from the Osprey Platform has been added. The net result is an increase in estimated discharges under the Permit of 0.966 mgd. HAK has decreased by 0.084 mgd overall while CIE, a new discharger, has introduced another 1.05 mgd due to the request to initiate discharges of produced water from Osprey Platform. Hence, the estimated total flows of produced water in the Permit indicate an expansion due to the new addition of the Osprey (See Section 10.4.1).

4.6.4 Facility-Specific Produced Water Effluent Characteristics

Produced water effluent characterization is necessary to derive maximum probable parameter concentrations that are used to evaluate and size mixing zones as well as maximum expected concentrations (MECs) used in the reasonable potential analysis (RPA). The objective of characterization is to categorize parameters based on their likelihood of exceeding water quality criteria or existing limits. Only those parameters that warrant consideration as being a driving parameter for mixing zones or have reasonable potential to exceed, or contribute to an exceedance, of water quality criteria and require a water quality-based effluent limit (WQBEL). The current Department procedures established in *RPA and Water Quality-based Effluent Limits (WQBEL) Development Guide, June 30, 2014 (RPA&WQBEL Guide)* focus on the driving parameters for each mixing zone as the typical parameters that require a WQBEL. There are many cases where effluent characterization data is sufficient to determine which parameter requires the most dilution to meet applicable water quality and, thus, determines the size and dilution factor required for the acute or chronic mixing zone. Because slightly less than the required dilution is authorized, each of the driving parameters will have reasonable potential at the boundary of the acute or chronic mixing zone and require a WQBEL. When the driving parameter is not obvious based on characterization data, then it must be determined though application of statistical procedures for applying multipliers to the maximum observed concentrations to derive the probable maximum concentration for the mixing zone. For more information, see Appendix B and Appendix C. The following sections provide a characterization of facility-specific produced water discharges observed during the period of review and compares this data with facility-specific limits from the 2007 GP and applicable water quality criteria.

4.6.4.1 Trading Bay Production Facility

TBPF is an onshore facility that receives multi-phase fluids (crude, gas, and produced water) from the King Salmon, Dolly Varden, Grayling, Monopod and Steelhead Platforms (See Figure 2). This facility has process/treatment equipment (improved gas flotation) to enhance the separation of the multi-phase fluids for recovery of oil and gas for sale. The enhanced treatment also reduces pollutants in produced water discharges.

In general, effluent data from DMRs for onshore production facilities were reviewed over a period representing the time that HAK began to take ownership of Cook Inlet facilities in 2012 through 2015. Because the preferred processing of produced water is to route to onshore facilities, current platform-specific data on produced water characteristics during this period is generally unavailable. DEC requested a comprehensive evaluation of the most current data and, when no data was available for certain parameters, to propose surrogate data to represent those data gaps. For the Osprey Platform that has not discharged produced water, DEC required sampling of the produced water currently being injected after treatment at the KPF with the results submitted in a revised application. The characterization data for all proposed produced water discharges were critically evaluated by DEC.

While evaluating characterization data, outliers were identified either associated with upset conditions or data that does not meet the definition of sufficiently sensitive (i.e., the analytical results were below the method detection level and was above the acute water criteria). In these situations, the data was not included in the evaluation. However, non-detectable results that were lower than acute criteria were included with the method detection level used as the value in the characterization summary. Table 16 provides a summary of the TBPF produced water effluent characteristics and compares this data with the limits from the 2007 GP and acute, chronic, and human health (HH) criteria from WQS.

Table 16: Trading Bay Production Facility Produced Water Characterization (1/2012 to 7/2015)

Parameter (Units) [1]	Data [2]	Limits		Water Quality Criteria			Observed Range [3] Min – Max, Average
		MDL	AML	Acute	Chronic	HH	
Oil and Grease	45/45	42	29	--	--	--	1.93 – *40*; 22.1
TAH (mg/L)	43/43	27	18	--	.010	--	**3.5 – 11.8; 8.2**
TAqH (mg/L)	43/43	--	--	--	.015	--	**3.4 – 11.9; 8.3**
Ammonia as N (mg/L) [4]	16/16	--	--	12	1.8	--	1.45 – **8.34**; **5.78**
Copper (µg/L) [5]	27/47	117	47	5.8	3.73	1,300	3.12 – **19.9; 5.68**
Manganese (mg/L)	44/44	50	25	--	--	0.1	**1.27 – 2.2; 1.78**
Mercury (µg/L)	16/43	1.0	0.6	2.1	1.1	0.051	0.00054 – **0.466**; 0.05
Silver (µg/L) [6]	0/44	47	23	2.2	--	--	**--**
Zinc (µg/L)	10/44	1,900	900	95.1	86.1	69,000	< 5 – **125**; 30

Notes:
1. Metals are reported as total recoverable except mercury, which is reported at total.
2. Represents the number of detectable data points versus total data points [Dectected/Total].
3. Values that exceed chronic or acute water quality criteria are presented in bold. Values that exceed limits are italicized. Less than symbols designate value was non-detectable and value is the method detection limit.
4. The ammonia criteria is based on a temperature of 15 C°, pH of 8.0, and salinity of 20 parts per thousand (ppt).
5. Nine outliers removed from data. Eight data points were non-detectable with the method detection level above the acute water quality criteria.
6. All 47 data points were non-detectable outliers with the method detection level above the acute water quality criteria.

Based on the characterization data summarized above all parameters except oil and grease (a TBEL), manganese and silver appear to have concentrations that warrant consideration for being included in the mixing zone evaluation. Of these POCs, TAH is the obvious driving parameter for the chronic mixing zone and will require a WQBEL. Ammonia and copper

have concentrations that warrant further evaluation in the mixing zone evaluation to determine which one is the driving parameter for the acute mixing zone and require a WQBEL.

4.6.4.2 Middle Ground Shoal Onshore Facility

The MGS Onshore Facility is an onshore facility that can receive multi-phase fluids from MGS - A, MGS - C, Baker, and Dillon Platforms (See Figure 2). Similar to TBPF, MGS Onshore operates efficient process/treatment systems so routing onshore has both economic and environmental incentives. Table 17 provides a summary of the MGS Onshore produced water effluent characteristics and compares this data with the limits from the 2007 GP and acute, chronic, and HH criteria from WQS.

Table 17: MGS Onshore Production Facility Produced Water Characterization

Parameter (Units) [1]	Data [2]	Limits		Water Quality Criteria			Observed Range [3] Min – Max, Average
		MDL	AML	Acute	Chronic	HH	
Oil and Grease	46/46	42	29	--	--	--	5.3 – *51*; 17.9
TAH (mg/L)	41/41	32	24	--	.010	--	**4.77 – 18.93; 14.54**
TAqH (mg/L)	41/41	--	--	--	.015	--	**4.83 – 19.33; 14.77**
Ammonia as N (mg/L) [4]	14/14	--	--	12	1.8	--	1.7– **8.5**; **5.36**
Copper (µg/L) [5]	8/13	90	60	5.8	3.73	1,300	< 2.5 – **7.02; 4.38**
Manganese (mg/L)	14/14	15.8	7.9	--	--	0.1	**1.32 – 2.74; 2.12**
Mercury (µg/L) [6]	0/14	0.8	0.5	2.1	1.1	0.051	--
Silver (µg/L) [5]	10/13	149	46	2.2	--	--	< 0.001 **– 28.1, 9.51**
Zinc (µg/L)	7/14	6,100	3,100	95.1	86.1	69,000	< 2.5 – **153**; 33.7

Notes:
1. Metals are reported as total recoverable except mercury, which is reported at total.
2. Represents the number of detectable data points versus total data points [Dectected/Total].
3. Values that exceed chronic or acute water quality criteria are presented in bold. Values that exceed limits are italicized. Less than symbols designate value was non-detectable and value is the method detection limit.
4. The ammonia criteria is based on a temperature of 15 C°, pH of 8.0, and salinity of 20 ppt.
5. One outlier removed as a non-detectable with the method detection level above the acute water quality criteria.
6. All 14 data points were non-detectable outliers with the method detection level above the acute water quality criteria.

Based on the characterization data summarized above all water quality parameters appear to have concentrations that warrant consideration for being included in the mixing zone evaluation. Of these POCs, TAH is the obvious driving parameter for the chronic mixing zone while silver is the driving parameter for the acute mixing zone and both will require a WQBEL.

4.6.4.3 Granite Point Tank Farm

GPTF is an onshore facility that can receive multi-phase fluids from the Anna, Bruce, Spark, Spurr and Granite Point Platform (GPP) (See Figure 2). Table 18 provides a summary of the GPP produced water effluent characteristics and compares this data with the limits from the 2007 GP and acute, chronic, and HH criteria from WQS.

Table 18: GPTF Production Facility Produced Water Characterization

Parameter (Units) [1]	Data [2]	Limits		Water Quality Criteria			Observed Range [3] Min – Max, Average
		MDL	AML	Acute	Chronic	HH	
Oil and Grease	67/67	42	29	--	--	--	12 – *75.48*; 28.1
TAH (mg/L)	67/67	20	14	--	.010	--	**3.47 – *19.52*; 11.68**
TAqH (mg/L)	21/35	--	--	--	.015	--	**3.59 – 19.61; 11.74**
Ammonia as N (mg/L) [4]	14/14	--	--	12	1.8	--	1.83– **15.4**; **9.29**
Copper (µg/L) [5]	17/35	130	67	5.8	3.73	1,300	2.07 – **40.9; 8.94**
Manganese (mg/L)	35/35	12.3	6.1	--	--	0.1	0.1 – **1.08; 0.29**
Mercury (µg/L)	25/35	7.9	3.1	2.1	1.1	0.051	0.00083 – **0.347; 0.087**
Silver (µg/L) [6]	0/40	74	37	2.2	--	--	--
Zinc (µg/L)	21/35	3,100	1,500	95.1	86.1	69,000	< 5 – **413**; 68

Notes:
1. Metals are reported as total recoverable except mercury, which is reported at total.
2. Represents the number of detectable data points versus total data points [Dectected/Total].
3. Values that exceed chronic or acute water quality criteria are presented in bold. Values that exceed limits are italicized. Less than symbols designate value was non-detectable and value is the method detection limit.
4. The ammonia criteria is based on a temperature of 15 C°, pH of 8.0, and salinity of 20 ppt.
5. Two outliers removed as a non-detectable with the MDLs above the acute water quality criteria.
6. All 40 data points were non-detectable outliers with the MDL above the acute water quality criteria.

Based on the characterization data summarized above all water quality parameters appear to have concentrations that warrant consideration for being included in the mixing zone evaluation. Of these POCs, TAH is the obvious driving parameter for the chronic mixing zone while copper is the driving parameter for the acute mixing zone and each will require a WQBEL.

4.6.4.4 Baker Platform

When operating, the Baker Platform sends multi-phase fluids to the MGS Onshore for the enhanced separation and recovery of oil and gas (See Figure 2). The Baker has not been actively staffed or operated in the past few years, has not discharged produced water since 2005, but could be slated for reactivation during the term of the Permit. Accordingly, the permittee has requested continued authorization of produced water as a contingency.

Since the Baker Platform has not been discharging for the past 10 years, representative data from the most recent discharge reports (April 1999 to June 2003) were used to complete the data set for evaluation. However, not all parameters warranting evaluation were being monitored during this period. Therefore, HAK provided data from MGS Onshore as a surrogate for this missing data. The effluent characterization data in Table 19 is from the most recent discharge data available or representative surrogates as noted in the table.

Table 19: Baker Platform Produced Water Characterization

Parameter (Units) [1]	Data [2]	Limits		Water Quality Criteria			Observed Range [3] Min – Max, Average
		MDL	AML	Acute	Chronic	HH	
Oil and Grease [4]	--	42	29	--	--	--	--
TAH (mg/L) [5]	45/45	257	128	--	.010	--	**6.99 – 28.0; 12.43**
TAqH (mg/L) [5]	45/45	--	--	--	.015	--	**7.26 – 29.0; 12.78**
Ammonia as N (mg/L) [7]	14/14	--	--	12	1.8	--	4.2– **8.5**; **5.4**
Copper (µg/L) [8, 9]	8/13	873	435	5.8	3.73	1,300	3.29 – **7; 4.9**
Manganese (mg/L) [9]	14/14	14.2	7.1	--	--	0.1	**1.32 – 2.74; 2.12**
Mercury (µg/L) [6]	1/12	0.4	0.3	2.1	1.1	0.051	**< 0.1** – **0.23; 0.11**
Silver (µg/L) [9]	10/13	347	173	2.2	--	--	< .001 **– 28.1, 9.5**
Zinc (µg/L) [6]	7	14,300	6,700	95.1	86.1	69,000	**304 – *8,000*; 2,120**

Notes:
1. Metals are reported as total recoverable except mercury, which is reported at total.
2. Represents the number of detectable data points versus total data points [Dectected/Total].
3. Values that exceed chronic or acute water quality criteria are presented in bold. Values that exceed limits are italicized. Less than symbols designate value was non-detectable and value is the method detection limit.
4. Oil and grease was not included in the historic research. The focus was on parameters with numeric water quality criteria for evaluation of WQBELs (i.e., TAH and TAqH). Oil and grease is a TBEL.
5. Because both the Baker and Dillon Platforms target the same formation, available data from the Dillon Platform from April 1999 through June 2003 is used as a surrogate.
6. Historic data from discharges at the Baker Platform from April 1999 through June 2003.
7. The ammonia criteria is based on a temperature of 15 C°, pH of 8.0, and salinity of 20 ppt.
8. One outlier removed as a non-detectable with the MDLs above the acute water quality criteria.
9. Surrogate data from MGS Onshore from January 2012 through April 2015.

Based on the characterization data summarized above all water quality parameters appear to have concentrations that warrant consideration for being included in the mixing zone evaluation. Of these POCs, TAH is the obvious driving parameter for the chronic mixing zone while zinc is the driving parameter for the acute mixing zone and each will require a WQBEL.

4.6.4.5 Bruce Platform

The Bruce Platform sends multi-phase fluids to GPTF for enhanced separation and recovery of oil and gas (See Figure 2). Although no discharge of produced water has occurred since 2006, the permittee requests continued authorization for produced water discharges from the Bruce Platform as a contingency. The characterization data from the most recently available DMRs from the Bruce Platform and other representative surrogate data sets are summarized in Table 20.

Table 20: Bruce Platform Produced Water Characterization

Parameter (Units) [1]	Data [2]	Limits		Water Quality Criteria			Observed Range [3] Min – Max, Average
		MDL	AML	Acute	Chronic	HH	
Oil and Grease [4]	--	42	29	--	--	--	--
TAH (mg/L) [5]	42/42	143	78	--	.010	--	**4.02 – 28.99; 17.3**
TAqH (mg/L) [6]	--	--	--	--	.015	--	**--**
Ammonia as N (mg/L) [7, 8]	14/14	--	--	12	1.8	--	1.83– **15.4**; **9.29**
Copper (µg/L) [9]	20/20	2,867	1,429	5.8	3.73	1,300	3.2 – **33; 16.34**
Manganese (mg/L) [8]	35/35	14.4	7.2	--	--	0.1	0.1 – **1.08; 0.2**9
Mercury (µg/L) [9, 10]	7/20	9.2	3.7	2.1	1.1	0.051	**< 0.2** – **1.69; 0.38**
Silver (µg/L) [5, 10]	15/43	11.0	7.3	2.2	--	--	.0729 **– 10.1,** 2.19
Zinc (µg/L) [9]	15/15	47,000	28,000	95.1	86.1	69,000	**501 – 8,260; 2,200**

Notes:

1. Metals are reported as total recoverable except mercury, which is reported at total.
2. Represents the number of detectable data points versus total data points [Dectected/Total].
3. Values that exceed chronic or acute water quality criteria are presented in bold. Values that exceed limits are italicized. Less than symbols designate value was non-detectable and value is the method detection limit.
4. Oil and grease was not included in the historic research. The focus was on parameters with numeric water quality criteria for evaluation of WQBELs (i.e., TAH and TAqH). Oil and grease is a TBEL.
5. Historic data from discharges at the Bruce Platform from January 2003 through June 2006.
6. TAqH was not monitored at the Bruce Platform when data is available.
7. The ammonia criteria is based on a temperature of 15 C°, pH of 8.0, and salinity of 20 ppt.
8. Data from the GPTF from June 2012 through July 2015 is used as a surrogate.
9. Because both the Bruce and Anna Platforms target the same formation, available data from the Anna Platform from January 2003 through May 2004 is used as a surrogate.
10. One outlier removed as a non-detectable with the MDLs above the acute water quality criteria.

Based on the characterization data summarized above, all water quality parameters appear to have concentrations that warrant consideration for being included in the mixing zone evaluation. Of these POCs, TAH is the obvious driving parameter for the chronic mixing zone while zinc is the driving parameter for the acute mixing zone and each will require a WQBEL.

4.6.4.6 Dillon Platform

The Dillon Platform has not discharged produced water since 2003 since it began sending multi-phase fluids to MGS Onshore for processing/treatment (See Figure 2). Although the Dillon has not been actively staffed or operated in the past few years, it could potentially be reactivated during the term of the Permit. Accordingly, the permittee has requested continued authorization of produced water as a contingency. The characterization data from the most recently available DMRs from the Dillon Platform and other representative surrogate data sets are summarized in Table 21.

Table 21: Dillon Platform Produced Water Characterization

Parameter (Units) [1]	Data [2]	Limits		Water Quality Criteria			Observed Range [3] Min – Max, Average
		MDL	AML	Acute	Chronic	HH	
Oil and Grease [4]	--	42	29	--	--	--	--
TAH (mg/L) [5]	45/45	42	31	--	.010	--	**6.99 – 28.2; 12.43**
TAqH (mg/L) [5]	45/45	--	--	--	.015	--	**7.26 – 28.0; 12.65**
Ammonia as N (mg/L) [6, 7]	14/14	--	--	12	1.8	--	1.7– **8.5**; **5.36**
Copper (µg/L) [7, 8]	8/13	14.0	9.3	5.8	3.73	1,300	< 2.5 – **7.02; 4.38**
Manganese (mg/L) [7]	14/14	4.6	2.3	--	--	0.1	**1.32 – 2.74; 2.12**
Mercury (µg/L) [5]	1/12	2.5	1.2	2.1	1.1	0.051	**<0.1** – **0.4; 0.125**
Silver (µg/L) [7, 8]	10/13	55	28	2.2	--	4,600	< 0.1 **– 28.1, 9.51**
Zinc (µg/L) [5]	45/45	2,300	1,200	95.1	86.1	69,000	4 – ***1,400*; 667**

Notes:
1. Metals are reported as total recoverable except mercury, which is reported at total.
2. Represents the number of detectable data points versus total data points [Dectected/Total].
3. Values that exceed chronic or acute water quality criteria are presented in bold. Values that exceed limits are italicized. Less than symbols designate value was non-detectable and value is the method detection limit.
4. Oil and grease was not included in the historic research. The focus was on parameters with numeric water quality criteria for evaluation of WQBELs (i.e., TAH and TAqH). Oil and grease is a TBEL.
5. Historic data from discharges at the Dillon Platform from April 1999 to December 2002.
6. The ammonia criteria is based on a temperature of 15 C°, pH of 8.0, and salinity of 20 ppt.
7. Data from the MGS Onshore from January 2012 through April 2015 is used as a surrogate.
8. One outlier removed as a non-detectable with the MDLs above the acute water quality criteria.

Based on the characterization data summarized above all parameters except oil and grease (a TBEL) and manganese appear to have concentrations that warrant consideration for being included in the mixing zone evaluation. Of these POCs, TAH is the obvious driving parameter for the chronic mixing zone and will require a WQBEL. For the acute mixing zone, the driving parameter is not obvious based on characterization. Silver and zinc will be included in the mixing zone evaluation to determine the driving parameter that establishes the acute mixing zone and will require a WQBEL.

4.6.4.7 Tyonek A Platform

The Tyonek A Platform is a gas production platform that has not discharged produced water since 2003 since it began injecting fluids rather than discharging. Although the Tyonek A plans to continue injection, the permittee has requested continued authorization of produced water discharges as a contingency to the possibility of an injection well shut-in. The characterization data from the most recently available DMRs from December 2000 through October 2003 for the Dillon Platform is summarized in Table 22

Table 22: Tyonek A Platform Produced Water Characterization

Parameter (Units) [1]	Data [2]	Limits		Water Quality Criteria			Observed Range [3] Min – Max, Average
		MDL	AML	Acute	Chronic	HH	
Oil and Grease [4]	--	42	29	--	--	--	--
TAH (mg/L)	16/16	0.14	0.090	--	.010	--	**0.014 – 0.064; 0.032**
TAqH (mg/L)	34/34	--	--	--	.015	--	0.011 – **0.69; 0.063**
Ammonia as N (mg/L) [5]	5/5	--	--	12	1.8	--	**3.34 – 6.1; 4.7**
Copper (µg/L)	19/30	1,033	328	5.8	3.73	1,300	< 0.75 – **272; 16.3**
Manganese (mg/L) [6]	--	0.2	0.1	--	--	0.1	--
Mercury (µg/L) [7]	0/11	0.1	0.05	2.1	1.1	0.051	--
Silver (µg/L) [8]	0/3	411	205	2.2	--	--	--
Zinc (µg/L)	1/2	17,000	8,400	95.1	86.1	69,000	4.83 - < 7; 5.9

Notes:
1. Metals are reported as total recoverable except mercury, which is reported at total.
2. Represents the number of detectable data points versus total data points [Dectected/Total].
3. Values that exceed chronic or acute water quality criteria are presented in bold. Values that exceed limits are italicized. Less than symbols designate value was non-detectable and value is the method detection limit.
4. Oil and grease was not included in the historic research. The focus was on parameters with numeric water quality criteria for evaluation of WQBELs (i.e., TAH and TAqH). Oil and grease is a TBEL.
5. The ammonia criteria is based on a temperature of 15 C°, pH of 8.0, and salinity of 20 ppt.
6. Manganese data for Tyonek A is not available.
7. All eleven samples collected for mercury were below the detection limit of 0.2 µg/L.
8. All three samples collected for silver were below the detection limit of 1.0 µg/L.

For Tyonek A, the characterization data summarized above indicates the parameters TAH, TAqH, ammonia, and copper have concentrations that warrant being considered for included in the mixing zone evaluation. The characterization of produced water effluent from the Tyonek A, a gas production platform, has noticeable differences between the other platforms that produce primarily oil with some gas. Oil platforms tend to have TAH as the driving parameter. Because of the high concentration of copper in the effluent the relatively low acute and chronic water quality criteria, copper is the obvious driving parameter for both the chronic and acute mixing zones, which will require development of a single WQBEL.

4.6.4.8 Osprey Platform

The Osprey Platform has not discharged produced water previously and has been injecting fluids rather than discharging. Although the Tyonek A plans to continue injection in the near-term, the permittee realizes that injection practices are no longer a practicable long-term disposal alternative. Accordingly, the applicant has requested to be considered for authorization of produced water discharges under the Permit so they can continue to operate. Because there is no historic data that can be used for evaluation mixing zones and effluent limits, DEC requested that CIE characterize their produced water waste stream that is currently injected. The characterization data from samples collected from September 5, 2017 through December 11, 2017 for the Osprey Platform is summarized in Table 23.

Table 23: Osprey Platform Produced Water Characterization

Parameter (Units) [1]	Data [2]	Limits [3]		Water Quality Criteria			Observed Range [3] Min – Max, Average
		MDL	AML	Acute	Chronic	HH	
Oil and Grease [4]	6/6	42	29	--	--	--	*39.4 – 64.3; 53.2*
TAH (mg/L)	12/12	--	--	--	.010	--	**4.33 – 9.93; 5.94**
TAqH (mg/L)	12/12	--	--	--	.015	--	**4.50 – 7.11; 6.18**
Ammonia as N (mg/L) [5]	--	--	--	12	1.8	--	**--**
Copper (µg/L) [6]	8/12	--	--	5.8	3.73	1,300	1.76 – **71.3; 14.92**
Manganese (mg/L)	12/12	--	--	--	--	0.1	**0.361** – **1.8**; **1.39**
Mercury (µg/L) [7]	7/12	--	--	2.1	1.1	0.051	0.004 - .**088**; 0.047
Silver (µg/L) [8]	0/12	--	--	2.2	--	--	**--**
Zinc (µg/L) [9]	10/12	--	--	95.1	86.1	69,000	5.99 – **670; 143.5**

Notes:
1. Metals are reported as total recoverable except mercury, which is reported at total.
2. Represents the number of detectable data points versus total data points [Dectected/Total].
3. Existing WQBELs are not available due to no previously permitted discharges of produced water. However, TBELs are applicable as these do not require pre-existing data for determination.
4. Values that exceed chronic or acute water quality criteria are presented in bold. Values that exceed limits are italicized. Less than symbols designate value was non-detectable and value is the method detection limit.
5. Ammonia characterization not requested for application.
6. Four outliers removed as a non-detectable with the method detection limits above the chronic water quality criteria for copper.
7. Five outliers removed as non-detectable with the method detection limits above the human health criteria for mercury. The seven detectable mercury results are from sufficiently sensitive methods.
8. All twelve samples were below detection with three of the method detection limits below acute water quality criteria.
9. Two of the zinc results were below detection limits of 50 µg/L.

Based on the characterization data summarized above all water quality parameters except silver warrant consideration for being included in the mixing zone evaluation. Although ammonia was not evaluated, DEC believes ammonia will be present in the effluent to the degree that dilution would be required to meet water quality criteria but not the degree of triggering reasonable potential. Of these POCs, TAH is the obvious driving parameter for the chronic mixing zone while copper is the driving parameter for the acute mixing zone and each will require a WQBEL.

Based on the six samples collected and analyzed for oil and grease, the Osprey cannot currently meet the ELGs per 40 CFR 435. In order to meet the oil and grease limits, the Osprey will need increased treatment of the produced water prior to discharge.

4.6.5 Produced Water Whole Effluent Toxicity Characteristics

The 2007 GP, and previous permits, required chronic WET monitoring of produced water discharges and stipulated a dilution series that bracketed limits that were based on the dilution factors of the authorized chronic mixing zones for chronic WET. The limits were also used as triggers for accelerated test and, potentially, TRE and TIE. As explained in Section 2.2.3.1, establishing a dilution series that bracket triggers was based on a pass/fail approach and led to poor characterization data. The dilution series applied to the WET tests were too low to capture the actual toxicity that is in higher dilutions so there was generally no observation of endpoints in the highest dilution series tested to adequately quantify toxicity in the effluent. Instead, reported results were typically a less than a relatively high TU_c value representing the highest dilution series test, which were too low due to bracketing the pass/fail triggers. Therefore, during permit development DEC requested modifications to dilution series for recent WET tests to address this fundamental concern and inform current permit decisions.

Not all of the eight facilities requesting coverage for produced water were able to conduct chronic WET testing with modified dilution series to supplement the application. Two of these

seven facilities are not currently in operation (Baker and Dillon) and the Bruce has not recently discharged produced water. In addition, Tyonek A Platform began injecting produced water in 2003 so data before 2003 is used in the characterization. For these facilities, older data has been used that may not reflect an accurate assessment of the chronic toxicity. For the onshore facilities and Osprey Platform, some chronic WET data using modified dilution series has been obtained to support revisions to their applications. These chronic WET results are based on observation of endpoints (i.e., actual values rather than < values). However, the maximum reported for the other platforms are likely based on the no observed effect concentration rather than observed endpoints and are marked with an asterisk (*). Table 24 compares this chronic WET characterization data to the WET MDLs and AMLs from the 2007 GP that were also used as triggers for accelerated testing.

Table 24: Produced Water WET Characterization

Facility	# Samples	Date Range	2007 GP MDL/AML	Maximum Reported Chronic WET	Sample Date
GPTF	14	2012 - Present	2,691/1,341	127	11/8/2017
TBPF	17	2012 - Present	568/283	233	2/1/2016
MGS Onshore	12	2012 - Present	2,425/1,209	152	2/1/2016
Baker	6	1999 - 2003	345/172	156*	2/1/2003
Bruce	10	1999 - 2006	4,312/2,149	313*	4/5/2005
Dillon	4	1999 - 2002	588/293	64*	10/1/2002
Tyonek A	12	1999 - 2003	537/268	64*	11/13/2000
Osprey	1	2017	--	63.29	7/7/2017

Based on the reported maximum WET results, most limits from the 2007 GP appear to be too high for controlling chronic toxicity in the discharge. The 2007 GP established MDLs by applying a multiplier to the highest reported chronic WET toxicity result to obtain a maximum expected chronic toxicity. The AMLs were calculated to be approximate one half of the MDLs. As a result, the dilution factors, and triggers, were significantly greater than that required to meet 1.0 TU_c at the boundary of the chronic mixing zone for most of the discharges. Over the last permit term, each facility that routinely sampled ran the dilutions bracketing the critical dilution based on the AML as required by the 2007 GP. These WET tests passed each time with a notable margin. In addition, the results provided no insight into actual toxicity because the dilution series was not allowed to be adjusted to bracket actual toxicity. When comparing the recent chronic WET results in Table 24 to the dilution factor authorized for the chronic mixing zones based on TAH as a driving parameter in Table 27, the imposition of chronic WET limits is not supported by 18 AAC 83.435(c) or 18 AAC 70.030. Based on the characterization, chronic WET must be included as a parameter in the chronic mixing zone but no RPA is warranted as the maximum reported chronic WET is typically an order magnitude less than the authorized dilution in the chronic mixing zones. Furthermore, chronic WET limits are not required because the chemical specific limits are sufficient to attain and maintain narrative and numeric water quality criteria; chronic WET criteria will always be met at the boundary of the chronic mixing zones based on TAH or copper as the driving parameter.

4.7 Completion, Workover, Well Treatment and Test Fluids (016-019)

Completion, treatment, workover, and test fluids injected downhole vary in their composition and are specific to various applications as described in subsequent sections. The specific definitions for completion, treatment, and workover fluids are contained in 40 CFR 435.41(ii), (jj), and (kk), respectively. The definition for test fluids was previously established in the 1986 GP and is provided in Appendix C of the Permit. The characteristics of these fluids are similar as they all

typically contain a large degree of formation water plus a portion of the fluids with chemical additions that were injected downhole.

Some completion, treatment, and test fluids may be oil-based fluids and have their continuous base consisting of mineral oil, or some other oil that has no synthetic materials or enhanced mineral oils. Biocides could be added to limit bacterial growth. Fluid returns from hydrocarbon formations are typically containerized and processed to remove oil because the fluid can be contaminated with hydrocarbons similar to produced water. Completion, treatment, and test fluids may also be treated using an OWS, or other removal process, and discharged via a shunt line below the water surface while drilling the exploration well. The volume estimates in Table 25 are from applications and indicates the combined volume could be up to 204,000 bbl. The POCs for completion, treatment, and test fluids include pH, oil and grease, oily sheen, TAH, TAqH, and chronic toxicity based on the nature of the formation water and the use of chemical additives. Accordingly, these water quality POCs are evaluated for a mixing zone in Section 6.2.3.7 for each of these three fluid types.

4.7.1 Completion Fluids (Discharge 016)

Well completion fluids are salt solutions (chloride, bromide, and formats), weighted brines, polymers, and various additives used to prevent damage to the well bore during operations that prepare the drilled well for hydrocarbon flow testing and production. The completion fluids may also target corrosion control, or be non-emulsifying mixtures. The intent of completion fluids is to enable pressure control management of the wellbore during the completions process, prior to testing or bringing a well online for production. The fluid composition may vary depending on the targeted formation and usually does not include solids (Schlumberger 2015).

4.7.2 Workover Fluids (Discharge 017)

Workover fluids are salt solutions, weighted brines, polymers, or other specialty additives used in a producing well to allow safe repair and maintenance or abandonment procedures. A well-control fluid, typically a brine, is used during workover operations. Since the wellbore is in contact with the reservoir during most workover operations, workover fluids should be clean and chemically compatible with the reservoir fluids and formation matrix (Schlumberger 2015). No discharge details from the previous two permit cycles are available on workover fluids.

4.7.3 Well Treatment Fluids (Discharge 018)

Well treatment fluids can be may be used for a wide range of purposes, such as stimulation, isolation or control of reservoir gas or water. Each fluid is designed to resolve a specific wellbore or reservoir condition and will contain specific ingredients (such as seawater, potassium chloride, diesel, or xylenes) relative to the intended application. The term “well treatment fluids” refers to any fluid used to restore or improve the productivity of a well by chemically or physically altering the oil-bearing subsurface geologic formations (strata) after a well has been drilled (Schlumberger 2015). No discharge details from the previous two permit cycles are available on well treatment fluids.

4.7.4 Test Fluids (Discharge 019)

Test fluids may contain a combination of formation water and injected freshwater or seawater with chemical additives. Test fluids generally consist of crude oil and water and are generated during well testing after drilling. Discharges may occur during exploration drilling, but in production and development scenarios the discharge will be processed so that any residual crude or hydrocarbon products are removed for their commercial value and the separated wastewater is treated prior to discharge. No discharge details from the previous two permit cycles are available on test fluids.

Table 25: Completion, Workover, Well Treatment and Test Fluids Discharged Volumes

Discharge Description (Number)	Average Discharge Volume per Well (bbls/well)	Maximum Discharge Volumes for 34wells (bbls)
Completion Fluids (016)	<1,500	51,000
Workover Fluids (017)	<1,500	51,000
Well Treatment Fluids (018)	<1,500	51,000
Test Fluids (019)	<1,500	51,000

These discharges are typically combined with produced water and sent onshore for treatment. The maximum total volumes provided are estimated from applications and an estimate of the maximum number of wells during the permit term.

5.0 COMPLIANCE HISTORY

Submittal of discharge monitoring reports (DMRs) are required monthly from all Permittees. During the review period, the method of reporting transitioned from paper to electronic submittals. The transition to electronic reporting per the EPA Electronic Reporting (eReporting) Rule (40 CFR 127) was initiated in December of 2016 for DMRs, and has been progressing in phases. The eReporting Rule also authorized NPDES programs delegated to States, including Alaska, to begin sharing DMR data electronically with EPA starting in December of 2016.

During permit development, DEC conducted an internal review reported violations in the Integrated Compliance Information System (ICIS) database to evaluate numerous inconsistencies and potential misinformation in the database. DEC discovered that there had been numerous non-reporting violations in ICIS that resulted from submitting a single DMR indicating there had been no discharge of drilling fluids when there are three separate DMRs for drilling fluids. Hence, the other three DMRs that were not also submitted cause ICIS to report non-compliance due to the missing DMR. On April 30, 2018 DEC sent a letter to HAK requesting a full review of their records in comparison to data from ICIS for the purpose of reconciling actual violations from false violations. Upon receipt of the full review from HAK on June 22, 2018 HAK and DEC collaborated on correction of inconsistencies and misinformation in ICIS. In addition, HAK provided an appropriate timeline from January through June 2018 that represents the period of ownership for each facility that is reflected in the compliance history in the following sections for facilities currently owned by HAK. Although many discrepancies were discovered and corrected for HAK, discrepancies for other permittees and facilities may exist without DEC knowledge. Therefore, DEC requests that permittees critically review this section for accuracy and report any discrepancies to the Department with their comments. The following compliance history review generally follows this timeline.

5.1 Reporting and Schedule Non-compliances

After reconciling false listings of reporting non-compliances, no reporting or schedule non-compliance resulted from review of the ICIS database.

5.2 Effluent Limit Exceedances

During the review period, effluent limit exceedances were reported for domestic wastewater and produced water discharges. No effluent limit exceedance were reported for the remaining discharge categories covered under the Permit.

5.2.1 Domestic Wastewater (Discharge 003)

According to DMRs, the domestic wastewater effluent limits were exceeded in the discharges from GPP, KLU Gas Production Julius R. Platform, and the Randolph Yost MODU. The parameters exceeding their respective effluent limits include BOD_5, TSS, pH, and TRC. The following subsections

provided details for each of these facilities and exceedances.

5.2.1.1 AKG315015 - GPP Domestic Wastewater Exceedances

The domestic wastewater discharges from the GPP exceeded the MDL or AML, and sometimes both limits for BOD_5 alone, TSS alone, and both BOD_5 and TSS during the months of March, June, July, and October in 2012, April in 2013, February, March and April in 2014, May in 2016, September, October, November and December in 2017, and January in 2018.

During the earlier portion of the review period, the effluent limit exceedances in the domestic wastewater discharge from GPP were sporadic and occasional. However, during the last quarter of 2017 and continuing through January of 2018, the effluent limit exceedances were appearing consistent, with 32 out of 33 exceedances in 2017 occurring during the last quarter alone.

The Permittee had self-reported these non-compliances starting in September of 2017 as the platform operations staff initiated numerous attempts to replace the parts, and to adjust the operation, of the domestic wastewater treatment unit at GPP so that the treated effluent would reliably meet the TSS and BOD_5 discharge limits. In April of 2018 the Permittee stated that ultimately, they were unable to determine the cause of the exceedances and could not operate the unit to reliably meet the TSS and BOD_5 limits. Therefore, instead of discharging, the permittee proposed commingling the domestic wastewater effluent with waterflooding and inject it into the UIC well. The permittee further requested a Compliance Order by Consent (Consent Order) for the proposed changes and civil penalties for the domestic wastewater exceedances since 2012, the time when the permittee assumed operation and ownership of the GPP.

The permittee proposed to begin construction during the summer of 2018 and anticipated discontinuing domestic wastewater discharges completely by August of 2018 and retain authorization to discharge under the Permit as a contingency to a UIC well shut-in. There were no further exceedances of effluent limits in the domestic wastewater discharge from GPP from February through the end of the review period.

5.2.1.2 AKG315102 - Randolph Yost MODU Domestic Wastewater Exceedances

During May 2016, the initial domestic wastewater discharges from the Randolph Yost MODU under the 2015 Exploration GP exceeded the AML for BOD_5 and TSS. The TSS value also exceeded the MDL. There have been no further domestic wastewater discharges from the Randolph Yost MODU under AKG315102 since May 2016.

5.2.1.3 AK0053686 - KLU Gas Production Julius R. Platform Domestic Wastewater Exceedances

The Randolph Yost MODU began development drilling at the KLU Gas Production Julius R. Platform on June 19, 2016. The wastewater treatment unit for the Randolph Yost MODU continued to experience system start-up issues, including power supply problems with the solids handling system, as well as salinity management and dechlorination contact timing issues. These resulted in effluent limit exceedances of the MDLs for TRC, TSS, and BOD_5 and occasionally, the AMLs for TSS and BOD_5 in during June through October 2016 under AK0053686. The Randolph Yost MODU ceased discharging domestic wastewater after October 2016.

The KLU Gas Production Julius R. Platform domestic wastewater discharge exceeded the MDL for TSS from November 2015 through January 2016, and also for BOD_5 in November 2015. However, none of the AMLs were exceeded. Upon investigating the cause, the Permittee determined that the system had been tampered with by unauthorized personnel. The Permittee completely drained and cleaned out the wastewater treatment system from December 2015 through January 2016. By February 2016, the discharge of the restarted system returned to compliance.

More recently, during the months of February and March in 2018, the pH in the discharge from domestic wastewater system at this platform did not meet the instantaneous minimum effluent limit of 6.5 SU. pH, with values ranging from 5.5 to 6.0 SU. The Permittee notified DEC of this non-

compliance, indicating that the potable water received at the platform had a high chlorine content. The cause for the low pH was not specifically determined. However, the permittee adjusted the additives used for dechlorination and continuing to monitor the pH levels. The pH of the discharge during subsequent months through the end of this review period were all in compliance with the effluent limits.

5.2.2 Produced Water (Discharge 015)

Per ICIS, the produced water effluent limits were exceeded in discharges from GPTF and TBPF. The parameters that were exceeded include oil and grease, TAH, silver, copper, and mercury. The following subsections provide details for each parameter and facility.

5.2.2.1 AKG315001 - GPTF Produced Water Exceedances

In December of 2012, 2013, and 2014 the produced water discharge exceeded the oil and grease effluent limits. Aromatic hydrocarbon concentrations exceeded the AML in December of 2012 and again in February of 2014. In May of 2015, the AML for total recoverable silver was exceeded. No effluent limit exceedances were reported from June of 2015 through the end of the review period. Enforcement actions were taken regarding the effluent limit exceedances and are discussed in Section 5.4.2.

5.2.2.2 AKG315002 – TBPF Produced Water Exceedances

At the Trading Bay Production Facility, both the daily maximum and monthly average limits for total mercury were exceeded in June 2012. The daily maximum and then the monthly average limits for total recoverable copper were exceeded in June 2012 and February 2016, respectively. No other effluent limit exceedances were reported through the end of the review period. Enforcement actions were taken regarding the effluent limit exceedances in 2017 and are discussed in Section 5.4.3.

5.3 Inspection Non-compliances

5.3.1 AKG315001 – GPTF Inspection Non-compliance

Inspection non-compliances at this facility are summarized along with the associated enforcement action in Section 5.4.2.

5.3.2 AKG315002 – TBPF Inspection Non-compliance

On April 24, 2015 DEC issued a Compliance Letter listing deficiencies identified as a result of an April 2, 2015 inspection as well as for effluent limit exceedances, failure to increase the associated frequency of sampling, and failure to notify the Department. The Permittee adequately responded in a letter dated May 21, 2015.

Inspection non-compliances at this facility in 2017 are summarized along with the associated enforcement action in Section 5.4.3.

5.3.3 AKG315003 MGS Onshore Inspection Non-compliance

An inspection January 19, 2017 revealed deficiencies in employee training records. DEC followed up with a Compliance Letter dated March 2, 2017. The Permittee adequately responded in a letter dated May 12, 2017 and, although not noted in ICIS, the non-compliance has been resolved.

5.3.4 AKG315004 - Anna Inspection Non-compliance

An inspection April 1, 2012 is shown as an unresolved non-compliance in ICIS with no further detail. However, DEC does not have a record of an inspection occurring for this facility in 2012. As a result, this inspection non-compliance has been treated as a data irregularity in ICIS.

5.3.5 AKG315008 - King Salmon Inspection Non-compliance

An inspection conducted in December 14, 2017 revealed deficiencies in recordkeeping of visual monitoring for the discharges of Domestic Wastewater (Discharge 004, Fire Control System Test Waste (Discharge 008), Noncontact Cooling Water (Discharge 009) and Waterflood (Discharge 014).

DEC followed up the inspection with a Compliance Letter on March 6, 2018. The Permittee adequately responded in a letter dated April 6, 2018 and, although not noted in ICIS, the non-compliance has been resolved.

5.3.6 AKG315009 - Dolly Varden Inspection Non-compliance

On February 16, 2018 DEC issued a Compliance Letter regarding a deficiency in visual monitoring of Fire Control Test Water (Discharge 008) identified as a result of a December 14, 2017 inspection. The Permittee adequately responded in a letter dated March 2, 2018 and, although not noted in ICIS, the non-compliance has been resolved.

5.4 Enforcement Actions

5.4.1 Potential Enforcement Action to HAK for Reporting and Schedule Non-compliance

Although Hilcorp was able to identify numerous cases of misinformation within ICIS, there were bona fide reporting and schedule non-compliance events flagged in ICIS. As of the writing of this Fact Sheet, the Department is still developing the enforcement actions that could be appropriate for these non-compliance events.

5.4.2 AKG315001 – GPTF Enforcement Action

On May 12, 2015 DEC issued a Compliance Letter to the Permittee as a result of an April 2, 2015 inspection and effluent limit exceedances during a period starting in 2012. On April 4, 2017 DEC issued a Compliance Letter listing deficiencies as a result of a March 23, 2017 inspection. In both cases, the Permittee responded to the Compliance Letters and fulfilled the requirements. A civil penalty in the amount of $48,591.10 was included in the Settlement Agreement. There are no unresolved enforcement actions associated with this permit authorization.

5.4.3 AKG315002 – TBPF Enforcement Action

On June 5, 2017, DEC issued a Notice of Violation (NOV) listing deficiencies identified during a May 9, 2017 compliance inspection, including the effluent limit exceedance, subsequent failure to increase the frequency of sampling and failure to notify the Department. The NOV was settled with the Permittee on May 22, 2018 with a civil penalty in the amount of $6,445.99.

5.4.4 AKG315015 – GPP Enforcement Action

As discussed in Section 5.2.1.1., a Consent Order per AS 46.03.020 was requested by the Permittee for effluent limit exceedances in the domestic wastewater discharge from the Granite Point Platform. A Consent Order is often used when a Permittee agrees to perform tasks in order to continue to operate while coming into compliance, and is an agreement that can be enforced by the state court system. The details of Consent Orders are confidential while in negotiation between Permittees and the Department. As of the time this Fact Sheet was prepared, the Consent Order was being negotiated and therefore details are still pending.

6.0 RECEIVING WATERS

Most of the existing development and production facilities in Cook Inlet are in coastal waters in the area north of a line extending across Cook Inlet at the southern edge of Kalgin Island (Figure 1). Cook Inlet is unique and noted for large tides, strong currents, extensive mudflats, high turbidity, and fluctuations in salinity due to large glacial and freshwater inputs from surrounding drainages. A comprehensive description of Cook Inlet oceanographic is provided in Appendix A.

6.1 Water Quality Standards

Any part of a waterbody for which the water quality does not, or is not expected to, intrinsically meet applicable water quality criteria is defined as a "water quality limited segment" and placed on the state's impaired waterbody list. For an impaired waterbody, Section 303(d) of the CWA requires states to develop a Total Maximum Daily Load (TMDL) management plan for the waterbody. The TMDL documents the amount of a pollutant a waterbody can assimilate without violating water quality criteria and allocates that load to known point sources and nonpoint sources. Cook Inlet is not included on the Alaska's Final 2010 Integrated Water Quality Monitoring and Assessment Report, July 15, 2010 as an impaired waterbody nor is the subject waterbody listed as a CWA 303(d) waterbody as requiring or having a TMDL. Accordingly, a TMDL is not applicable to development of mixing zones for the Permit. Mixing zones in the Permit have been developed in compliance with 18 AAC 70.240 -.270 as amended June 26, 2003 and currently approved by EPA for use in APDES permits.

6.2 Mixing Zones

6.2.1 Overview

During permit development, DEC required revised mixing zone applications that included critical review of historic and new information to inform DEC decisions on mixing authorizations. Data detailing salinity profiles and tidal currents in the vicinity of the discharges were used to improve upon previous mixing zone modeling (See Section 2.3.2). Conductivity, temperature, and depth (CTD) data collected during ICIEMAP was used to refine stratification profile assumptions used to model critical conditions associated with stratification. The ICIEMAP data also provided new information on ambient metal concentrations. Buoy deployments by the NOAA provided addition time-dependent current data at various locations in upper Cook Inlet that allowed for interpolation and extrapolation of current speeds to facilities in various regions modeled in Cook Inlet. The NOAA data also provided information on slack tide currents used to evaluate re-entrainment of the plume after tidal reversals (See Appendix A – Cook Inlet Description). Mixing zone models and data from individual permits for other facilities in Cook Inlet were evaluated and this information was used to broaden the regional understanding of hydrodynamics and provide facility-specific mixing zones. New modules in the CORMIX Version 11 for discharges of drilling fluids and drill cuttings and surface discharges for miscellaneous discharges were used to improve and validate previously established mixing zones. Discharge outfall information was critically reviewed to solidify discharge port properties for use in CORMIX. When information was unavailable or insufficient, a sensitivity analysis was conducted to determine appropriate assumptions to model mixing zones. All these efforts have led to significant refinement in the mixing zone evaluation provided in previous permits.

Mixing zones in the Permit are based on the 2003 WQS and further supported by empirical studies and mixing zone modeling validation. For discharges that can be categorized based on meeting constraints consistent with those considered during the mixing zone evaluation are authorized a standardized mixing zone under the Permit. For example, the 2015 Exploration GP included standardized 100 meter cylindrical mixing zones for drilling fluids and drill cuttings

based on empirical data collected during the COST Study. During development of the Sabre IP, DEC used a new module in CORMIX developed specifically for the discharge of drilling fluids and drill cuttings and validated the 100 meter mixing zone previously determined empirically to demonstrate the appropriateness of the standardized mixing zone (See Section 2.2.5). In addition, with the new requirement for dechlorination of domestic wastewater (Discharge 003) and limiting the TRC to 1/mg/L, DEC is able to apply standardized mixing zones for many of these discharges as well. Note that establishing a 1 mg/L limit for TRC also resulted in a reduction of the standardized mixing zone for domestic wastewater from 100 meters in the 2007 GP and 2015 GP to 35 meters in the Permit. By ensuring adequate constraints are placed on discharges and consistency with modeled mixing zone conditions, standardized mixing zones protect the waterbody as a whole and provides an efficient and effective authorization process under general permits. However, when discharges are so unique that they cannot be categorized or effectively constrained to effectively develop a standardized mixing zone, a facility-specific mixing zone may be appropriate.

When receiving water conditions or discharge characteristics and flow rates of the effluent are too varied, a facility-specific mixing zone has been specified in the Permit (e.g., certain domestic wastewater, miscellaneous discharges and produced water). In these situations, the facility and location are known such that specific mixing zone can be developed and included in the Permit and authorized upon receiving an NOI. When the facility or location is not known but the characteristics of the effluent can be adequately determined or constrained, a facility mixing zone can still be authorized under the Permit. This is accomplished by evaluating the mixing zone and other permit conditions necessary to satisfy 18 AAC 70 and 18 AAC 83 and developing a statement of basis and following administrative procedures in 18 AAC 15 and 18 AAC 83 during the NOI process prior to issuing an authorization. Because in these situations the mixing zone determination and, potentially, other conditions have not been subject to the public notice procedures, the Department determinations must be noticed for a 30-day public comment period. Upon developing a statement of basis and satisfying the public notice procedures, DEC can then issue the mixing zone as part of the authorization. This situation is anticipated to arise for HDD discharges, which have typical characteristics but the location and volume of discharge is a critical component for sizing the mixing zone that would not be known until the NOI process. In addition, this could also arise when there is not enough information for discharge characteristics and flow rates even though there is adequate knowledge on the receiving water such as with a new produced water discharge. For produced water discharges, the subsequent public process would include proposed WQBELs developed based on a full application submitted to the Department. Depending on the application, the Department may decide to issue an individual permit instead of an authorization under the Permit.

6.2.2 Mixing NOIs, Applications, and Authorizations

The Department may authorize a mixing zone under the Permit upon receipt of a complete application. In most cases, the NOI serves as the application for the Permit and provides information required to verify compliance with this section and the mixing zone checklist (See Appendix E - Mixing Zone Analysis Checklist). A mixing zone may be authorized based on meeting all regulatory criteria, as described in this fact sheet, which include consideration of: the size of the mixing zone, treatment technology, existing uses of the waterbody, human consumption, spawning areas (not applicable to marine waters and by extension the Permit), human health, aquatic life, and endangered species. Subsequent Sections 6.2.4 through 6.2.11 describe the rational used to meet the mixing zone criteria.

As discussed previously, request for mixing zones associated with HDD discharges cannot be issued based solely upon submittal of an NOI; a mixing zone application, Form 2M, must also

be submitted so that DEC can adequately evaluate the mixing zone per Appendix D. This evaluation and determination must follow public procedures prior to being included in an authorization under the Permit. Because the characteristics of drilling fluids for HDD are adequately covered in this Fact Sheet, inclusion of limits in the public notice documents is not necessary as the limits in the Permit are appropriate. For new produced water discharges, the applicant must submit a full application (Form 1, Form 2C, and Form 2M). Based on the application, DEC will decide whether to follow procedures to authorize the mixing zone, and WQBELs, under the Permit after public notice of Department determinations, or, to issue an individual permit (See Section 1.3).

6.2.3 Mixing Zone Analysis per Discharge

The following sections provide the mixing zone sizing methodology per discharge category.

6.2.3.1 Oil and Gas Drilling Fluids and Drill Cuttings (001) and Mud, Cuttings, and Cement at the Seafloor (013)

The Department is authorizing a 100 meter mixing zone for the discharge of drilling fluids and drill cuttings (Discharge 001) and mud, cuttings, and cement at the seafloor (Discharge 013) for the water quality parameter turbidity for discharges related to oil and gas exploration, development, and production. Authorization is available for fixed platforms as well as MODUs. To account for trace metals attached to barite and clay in the drilling fluid, the authorization includes arsenic, cadmium, chromium, copper, lead, mercury, nickel, selenium, silver, thallium, and zinc. These metals are listed in the chronic mixing zone to be consistent with the authorized zone of deposit even though they are not anticipated to be solubilized in the water column (See discussion for barite in Section 4.1.3).

The authorized chronic mixing zone of 100 meters for the discharge of oil and gas drilling fluids and drill cuttings is primarily based on empirical data from COST Study (1976) based on an understanding that the critical receiving water and effluent conditions are comparable when the depth-dependent discharge limitations are adhered to. The location of the COST Study was in a net erosional area. Some locations in the coverage may have sediment conditions that represent a transitional environment (neither net depositional or erosional), characterized to have a predominantly sandy bottom that may also include silt, gravel, and boulders. Although the location of the well in the COST Study was in a net erosional environment, the impacts of this difference on modeling dispersion is not significant as the fate and transport of drilling fluids in the water column is driven primarily by current speeds at the location and the rate of discharge, which is limited. Because the critical currents, 90th percentile, within the area of coverage are consistently above 2.3 m/s (Parametrix 2017) and the depth-dependent discharge limitations ensure sediment transport capabilities in the water column are not exceeded, the standardized 100 meter mixing zone is appropriate in these situations.

The ability to model drilling fluids and drill cuttings is a recent upgrade to CORMIX. DEC verified the appropriateness of the 100 meter mixing zone using CORMIX modeling during issuance of the Sabre IP based on typical drilling fluids and receiving water conditions at the Sabre project site that represent a transitional sediment condition. Given the transitional nature of the project site, the results of the modeling represent a conservative validation when compared to an erosional site. The representative drilling fluid is characterized as mixture of 24 % drill cuttings with spud drilling fluid and 33 % cuttings with KCL fluid. The relative amount of fines versus cuttings is assumed to be approximately a 4:1 ratio. The specific gravity of fresh water (1.0) and the assumed specific gravity of sediment in Cook Inlet (2.65) are used to estimate the concentration of TSS in the final mixture of the discharge. The total fine sediment discharge was estimated to be 70,000 mg/L to 100,000 mg/L for the spud and KCl drilling fluids, respectively. These concentrations

representing the fine-grained fraction of TSS (silt, clay and sand) of the drilling fluids were used in the model to evaluate dispersion using the critical ambient currents, temperature, and stratification assumptions. The maximum discharge rate for drilling fluids and drill cuttings was limited to 500 bbls/hr (50,400 gpm or 2 liters per second) based on the dispersion available for the water depth at the location, approximately 14 meters.

Although the applicable water quality criteria for the mixing zone analysis is turbidity, it cannot be directly modeled using CORMIX that considers mass balance as a basis. The water quality criteria for turbidity is not a measurement of mass or concentration but rather a measure of reflected light scattered in the sample measured in nephelometric turbidity units (NTUs), which is dependent on grain size, structure, and the refractive index of the suspension. Instead of turbidity, the CORMIX model uses TSS concentrations and then the permitting authority must attempt to correlate the results for TSS with turbidity. Hence, the approach is an approximation dependent on availability and representativeness of paired data for TSS and turbidity that can result in a correlation at the specific site for specific suspensions of sediment.

A universal relationship does not exist between turbidity and TSS as the nature of the sediment greatly affects turbidity measurements and the nature of sediment in Cook Inlet can change spatially and temporally. One correlation between TSS and turbidity was developed specifically for Cook Inlet as part of the Knik Arm Bridge and Toll Authority (KABATA) studies (KLI 2007) whereby 25 NTUs is approximated by 32 mg/L TSS. This correlation is consistent with linear relationships between TSS and turbidity determined in settling column tests conducted by the Army Corp of Engineers (ACOE) at 32.5 mg/L. Correlation of field data resulted in a value of 43.8 mg/L (Thackston and Palermo 2004). These correlations are provided to demonstrate the appropriateness of the correlation from the KABATA studies. However, none of these correlations are specific to the both suspension (drilling fluids) and Sabre project site. A suspension of drilling fluid fines will have a very different correlation than the receiving water and the receiving water data from the KABATA may not represent that at the Sabre site. Hence, any correlation between TSS and turbidity should be used cautiously and conservatively.

Using a correlated estimate of an equivalent TSS concentration of 32 mg/L for turbidity criteria and the estimated TSS concentrations of percent fines in the two drilling fluid mixtures, 70,000 mg/L and 100,000 mg/L, the required dilution factors for the spud and KCl drilling fluids to meet turbidity criteria at the boundary of the chronic mixing zone are 2,188 and 3,125, respectively Using the calculations, critical conditions, and correlations discussed above, the CORMIX modeling results indicate that the plume is controlled primarily by initial mixing and density differences between the receiving water and effluent.

According to CORMIX modeling results, the discharge is not buoyant. However, due to slight stratification present in summer months, the plume disperses out to the boundary of the mixing zone in the upper few feet (approximately 1 meter) of water depth. Mixing is directed in the path of current movement, roughly following bathymetry elevations and coastline.

During the 90th percentile current, water quality equivalent concentrations are met at the boundary of the 100 meter radius mixing zone, and the mixing zone depth is about 2 meters thick. In these conditions, deposition is unlikely. The model predicts that settling of drilling fluid and drill cutting particles will not occur before WQS are met at the mixing zone boundary. However, the larger fraction of particles (drill cuttings) will settle to the bottom during the 10th percentile current conditions within a 25 meter radius zone and then become re-suspended or mixed with the transitioning bottom sediments during the next high current event. See Section 4.1.3 and Section6.3 for more on discussion on zone of deposits.

6.2.3.2 Drilling Fluids and Drill Cuttings for Geotech Surveys (Discharge 001)

The Department authorizes a 105 meter wide by 1,856 meter long (928 meters in each current direction, rectangular shaped chronic mixing zone with a dilution factor of 3.000 for drilling fluids and drill cuttings associated with geotechnical surveys. The size of the mixing zone is based on a modeling study conducted to support the AKLNG Cook Inlet 2015 Geophysical and Geotechnical Program (AKLNG Project). The AKLNG Project used a skid-mounted rotary drilling unit on the deck of small MODU capable of operating in depths up to 30 meters. Drilling fluids were used to circulate cuttings to the deck surface where drilling fluids were separated for reuse downhole and cuttings over-boarded. Drilling fluids were not discharged continuous but rather at the end of the borehole when the 10-inch diameter riser had to be raised out of the water. The volume of drilling fluids and drill cuttings remaining in the riser pipe exit the bottom of the pipe and disperse in the water column in the prevailing current direction. CORMIX was used similar to the modeling done for oil and gas drilling fluids using correlations TSS and turbidity while accounting for the depth relationships of the riser pipe. Although the AKLNG Project included two different sized mixing zones, one for the east and one for the west side of Cook Inlet, the Permit authorizes the larger of the two based on the west side as a conservative approach allowing for a standardized mixing zone. Hence, the larger mixing zone will ensure water quality criteria is met at various locations in the coverage area.

For discharges from geotechnical surveys, the coverage area is not restricted and can occur anywhere in state waters of Cook Inlet and is not limited to just oil and gas infrastructure projects. The nature of the discharges for geotechnical projects are not dissimilar to those for oil and gas. Authorization of the mixing zone is based on submitting an NOI and evaluation by the Department that requirements for coverage are met.

The parameters authorized in the mixing zone are dependent upon the classification of drilling fluid identified in the NOI. Class C1 and C2 Drilling Fluids are authorized for turbidity. Whereas, Class C3 Drilling Fluids are authorized for turbidity, arsenic, cadmium, chromium, copper, lead, mercury, nickel, selenium, silver, thallium, and zinc (barite metals).

6.2.3.3 Drilling Fluids and Drill Cuttings for HDD (Discharge 001)

While evaluating mixing zones for discharges of HDD to Cook Inlet, DEC reviewed mixing zone studies provided for the Furie IP and the Trans-Foreland Pipeline Project, which was not implemented. Upon review of these two studies, DEC determined that although the characteristics of the discharges could be categorized effectively for a standardized mixing zone, the unique components of HDD projects does not lend itself to standardization. These unique components include borehole diameters, elevation difference (hydrostatic head) that determines discharge velocity at breakthrough (daylighting) of the pilot hole, length of the borehole that affects the rate of attenuation after peak discharge, and plume modeling techniques. For these reasons, DEC requires submittal of a mixing zone application (Form 2M) along with the NOI that provides information on the drilling fluid to authorize a mixing zone. Because the sizing and evaluation of the mixing zone is not inclusive to this Fact Sheet, the mixing zone determination must comply with 18 AAC 70 (2003 version) and 18 AAC 83 and undergo due public process per 18 AAC 15 and 18 AAC 83. Upon developing a Statement of Basis and completion of the public notice procedures, DEC can authorize a site-specific mixing zone under the Permit for HDD discharges specifying the dimensions, dilution factor, and any conditions necessary for consistency with meeting requirements in the Mixing Zone Checklist in Appendix D.

Similar to geotechnical surveys, discharges from HDD are not restricted and can occur anywhere in state waters. DEC will require adequate information in the NOI and Form 2M to evaluate site-specific concerns and address them through the public process.

Also similar to geotechnical surveys, the authorized parameters are based on drilling fluid classifications identified in the NOI; Class C1 and C2 apply to turbidity and Class 3 apply to turbidity and barite metals described in Section 6.2.3.2.

6.2.3.4 Domestic Wastewater and Graywater (Discharge 003 and Discharge 004)

As discussed previously, DEC has established a TBEL maximum limit for TRC on domestic wastewater discharges of 1 mg/L for Discharge 003 - Domestic Wastewater. DEC also assumes that Discharge 004 - Graywater has a maximum TRC concentration of 1 mg/L when discharged separately from domestic wastewater. This established a consistent basis for evaluating mixing zones in order to derive standardized mixing zones for many facilities but also allowing for site-specific mixing zones for those that cannot fit standardization for unique reasons. The standardized mixing zone was based on a subset of the fixed platforms where site-specific analysis led to a consistent outcome. Standard mixing zones were applied to these fixed facilities as well as MODUs that must demonstrate through the NOI process to have similar characteristics as those modeled. The remaining existing fixed platforms either did not have specific information on discharge port configuration or had flow rates that were outside the standardized flow rate assumptions. For unknown port configurations or port configurations that could not be modeled in CORMIX, the applicant conducted a sensitivity analysis around the missing port configurations to bracket reasonable outcomes. For discharges with higher flow rates, DEC provides a mixing zone appropriately sized for the staffing needs of the existing facility, port configuration, and receiving water conditions at the facility. New fixed platforms or exploration MODUs that do not meet the requirement for a standardized mixing zone can obtain a facility-specific mixing zone by submitting a mixing zone application (Form 2M) with the NOI. As previously discussed, an authorization of a mixing zone in this scenario will follow appropriate public notification procedures prior to issuing the authorization under the Permit including the mixing zone. The following summarizes the resulting mixing zones based on facility type.

Standardized: For all exploration MODUs and the fixed platforms Anna, Baker, Bruce, Dillon, Dolly Varden, Grayling, King Salmon, Osprey, Steelhead, and Tyonek A DEC authorizes a standard 35-meter radii chronic and an 18-meter radii acute cylindrically-shaped mixing zones extending from the sea surface to the seafloor The authorized dilution factor are 133 for the chronic and 77 for the acute. Upon submitting an NOI that demonstrates applicability of coverage under the Permit, DEC will authorize these standardized mixing zones for Discharge 003 and/or Discharge 004.

Facility Specific: The Department may authorize the following facility-specific mixing zones upon receipt of an NOI by the applicant:

For the fixed platform MGS A, DEC authorizes a 123-meter radii chronic and a 94-meter radii acute, cylindrically-shaped mixing zones extending from the sea surface to the seafloor. The authorized chronic dilution factor is 133 and the acute dilution factor is 77.

For the fixed platform Granite Point, DEC authorizes a 213-meter radii chronic and a 155-meter radii acute, cylindrically-shaped mixing zones extending from the sea surface to the seafloor with a chronic dilution factor of 133 and an acute dilution factor of 77, respectively.

For the fixed platform Julius R, DEC authorizes a 20-meter radii chronic and an 11-meter radii acute, cylindrical mixing zones extending from the sea surface to the seafloor with a chronic dilution factor of 133 and an acute dilution factor of 77, respectively. This authorization applies to the fixed Julius R. Platform and any seasonal MODU that attaches to the platform for the purpose of conducting development and production drilling. A mixing zone authorization for an exploration MODU discussed previously does not apply to the MODU while attached to the Julius R Platform.

New Fixed Platforms or Exploration MODUs: New fixed platforms or exploration MODUs must submit a project-specific mixing zone application (Form 2M or another format approved by DEC) with the NOI for Department evaluation. If the applicant qualifies for a standardized mixing zone in Section, DEC will authorize the mixing zone with the authorization to discharge. If the applicant does not qualify for the standardized mixing zone (i.e., needs a larger mixing zone) DEC will evaluate the mixing zone application according to the most recent EPA-approved version of the mixing zone regulations in 18 AAC 70 and issue a 30-day public notice of a Statement of Basis and the Departments final determination to authorize a mixing zone per 18 AAC 83 and 18 AAC 15. The mixing zone authorization, if approved, will be included with the authorization to discharge under the Permit after following public notice procedures.

6.2.3.5 Miscellaneous (Discharges 005-014)

The 2007 GP did not establish mixing zones for fixed facilities or exploration MODUs discharging in coastal waters. Instead, chemical inventories and WET monitoring with triggers for accelerated testing were established, based on estimates of acute toxicity. In the final Certification of the 2007 GP, DEC did not believe there was adequate data to inform decision on mixing zones at the time and the intent was to obtain data for consideration during the next reissuance. For various circumstances, this intent was not realized (See Section 2.2.3.1 and 4.5.10). For the territorial sea and outer continental shelf, EPA established a standardized 100 meter mixing zone and chronic WET triggers equal to estimated dilution factors at the boundary of the mixing zone based on variable flow and whether the discharge was directly to the water surface or submerged. DEC used this same approach during issuance of the 2015 Exploration GP. DEC is now modifying this approach to reflect new information on chemical use and maximum expected chronic toxicity, new information on critical receiving water and effluent conditions, and new CORMIX abilities for modeling surface discharges. DEC also developed a consistent approach for establishing triggers based on mixing zone modeling and used toxicity estimates to inform PR strategies using chronic toxicity monitoring.

In the 2007 GP, Chronic WET monitoring was required based on two concurrent conditions, use of chemical additives and discharges greater than 10,000 gpd (0.010 mgd). This dual condition tended to limited chronic WET monitoring to two discharges, noncontact cooling water (Discharge 009) and waterflooding (Discharge 014). Although desalination waste can have chemicals, discharges are not typically over 10,000 gpd. To reconcile lack of chronic WET data that represents concentration spikes from batch dosing, DEC used revised estimates of chemical concentrations and toxicity data from SDSs to determine the potential maximum toxicity in discharges from applicable facilities (facilities using chemicals and discharging greater than 0.010 mgd). For characterization of noncontact cooling water and waterflooding, refer to Section 4.5.5 and 4.5.10, respectively. Instead of establishing triggers based on toxicity, DEC decided to establish triggers based on meeting the chronic toxic criteria of 1 TU_c at the boundary of 100 meter chronic mixing zones at various critical discharge flow rates. Once triggers were established, maximum estimated toxicity were used to inform PR strategies.

DEC conducted a critical evaluation of facility-specific modeling input parameters to improve upon previous mixing zone efforts. Similar to domestic wastewater modeling, when specific information was missing a sensitivity analysis was conducted to bracket the probable outcome. This effort resulted in a better understanding of which facilities discharge to the surface versus submerged and the size of the mixing zones needed to ensure chronic WET criteria is met at the boundary of the chronic mixing zones. The concept of a standardized 100 meter mixing zone was expanded to include exploration MODUs and all

fixed, or new, platforms to the extent possible. Certain discharges from existing facilities (MGS-C and Steelhead) were found to require mixing zones larger than 100 meters initially to ensure compliance with chronic toxicity criteria at the boundary. However, DEC anticipates that by the next permit term PR strategies will result in meeting criteria at the 100 meter. This is because the triggers used are associated with the dilution at 100 meters rather than the dilution authorized by the larger mixing zone. For more details see Section 8.5.4. Based on this intensive modeling effort, the following paragraphs summarize the authorized mixing zones, associated dilution factors, and applicable triggers for PR BMPs revisions discussed later.

Standardized Mixing Zones: The analysis of facility-specific mixing zones led to development of a new standardized mixing zone approach that may apply to new fixed facilities or exploration MODUs that apply under the Permit. The standardized mixing zone is 100 meters radius extending from the sea surface to the seafloor and applies to either direct surface discharges or submerged discharges. Surface discharges were evaluated at seven different existing fixed facilities that had varying flow rates and height above water surface. DEC determined there is a good correlation of dilution with flow rates that can be used to authorize dilution factors based on flow rates provided in an NOI. Based on the maximum flow rate in mgd among the miscellaneous discharges, the applicable dilution factor, and chronic WET PR BMP trigger, is governed by:

$$DF_c = 172.5 \times Flow^{-0.244} \qquad R^2 = 0.971$$

For submerged miscellaneous discharges, the Steelhead Platform was used as the model platform in the analysis for developing flow rates versus dilution. Steelhead was also the model platform in similar modeling in the 2007 GP. However, for this effort the information on the configuration of the discharge port and the critical conditions in the receiving water have been updated based on current information. Similar to the surface discharges, the model results using various flow rates for dilution resulted in a prediction curve with a high coefficient of correlation and is used to authorize dilution factors for a standardized 100 meter radii chronic mixing zone based on flow rates provided in an NOI. Based on the maximum flow rate in mgd among the miscellaneous discharges, the applicable dilution factor, and chronic WET PR BMP trigger, is governed by:

$$DF_c = 73.67 \times Flow^{-0.325} \qquad R^2 = 0.997$$

Facility Specific Mixing Zones: All existing fixed platforms and exploration MODUs have been modeled for either noncontact cooling water (exploration MODUs) or waterflooding (fixed platforms) mixing zones based on the estimated potential maximum toxicity and critical effluent flow rates. For all but two facilities, a 100 meter radii mixing zone has been authorized with an associated dilution factor. Two have been authorized to have a 300 meter radii mixing zone due to unique facility considerations. Table 26 summarizes these facility-specific mixing zones for existing fixed platforms or exploration MODUs authorized under the Permit.

Table 26: Facility-Specific Mixing Zones for Miscellaneous Discharges 005 through 014

Facility	Flow (mgd)	Discharge Condition	MZ Radii (meters)	DF_c
Granite Point Platform [1]	1.7	Surface	100	152
King Salmon Platform [1]	3.36	Surface	100	128
Monopod Platform [1]	3.33	Surface	100	129
Grayling Platform [1]	5.14	Surface	100	116
Dolly Varden [1]	5.21	Surface	100	115
Spartan 151 MODU [2]	0.132	Surface	100	189
Randolph Yost MODU [2]	2.1	Surface	100	173
Osprey Platform [3]	0.189	Submerged?	100	127
Steelhead Platform [2]	0.804	Submerged	300	189
MGS – C Platform [2]	0.132	Submerged	300	1,119

Notes:
1. Authorized dilution factors are based on equation for surface discharges.
2. Authorized dilution factors are based on actual modeled dilution to account for unique discharge conditions.
3. Authorized dilution factors are based on equation for submerged discharges.

6.2.3.6 Produced Water (Discharge 015)

One of the concerns raised from stakeholders during early outreach was that the produced water mixing zones did not adequately evaluate discharges during tidal reversals associated with slack tide and were sized primarily reflecting the maximum currents. The characteristics of the plumes in the 2007 GP were long and narrow and not likely depicting the actual plume behavior. During permit development, the applicant used newly available NOAA data that allowed for better analysis of slack tided conditions and applied modeling and practicable methods to determine better estimates of the width of the plume. Each discharge was evaluated for the potential for re-entrainment during tidal reversals but the currents evaluated from the NOAA stations did not support this concern; the currents that occurred around slack tide are generally not in the same directions as the high current directions such that the plume would reverse over itself. In addition, the current data from NOAA stations do not support modeling the discharges as an estuary, the current conditions are appropriately modeled as ocean.

A range of current percentiles were evaluated for each facility to determine critical current conditions. Although most facilities resulted in the 90th percentile determining plume length and the width using the 10th percentile, there were exceptions where other current percentiles represented critical conditions (e.g., TBPF and MGS Onshore). In general, the width dimensions were determined by modeling the 10th percentile current, or other percentile if appropriate, and then evaluating the applicable range of current directions during that period using the new NOAA data. For TBPF and MGS Onshore, this method had to be modified for facility-specific reasons. TBPF has a diffuser array and MGS Onshore has a single port aligned in the current direction, which makes modeling the discharge difficult in CORMIX. Except for TBPF, MGS Onshore, and Tyonek A, the analysis generally resulted in produced water mixing zones that are shorter than those in the 2007 GP and all have wider dimensions due to the new conservative approach for estimating plume behavior during tidal reversal at slack tide. Note that although the mixing zones became larger, this is reflective of taking a conservative approach with new information rather than due to increases in pollutants as there were also noted decreases in authorized dilution factors.

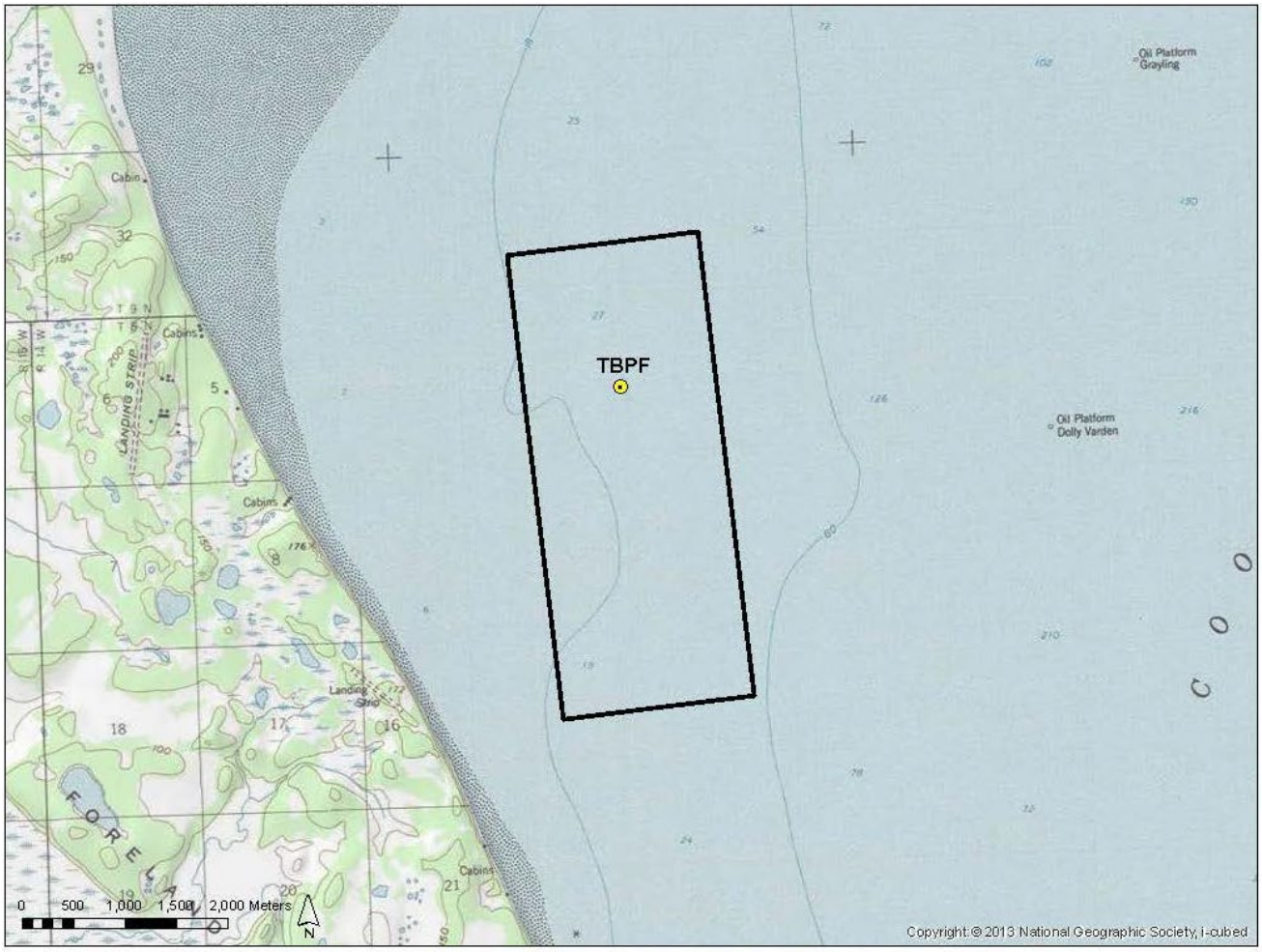
In all cases, facility-specific effluent and site-specific receiving water conditions were used to size produced water mixing zones. For all platforms except the Tyonek A, the size of the chronic mixing zones are driving by the probable maximum concentrations of TAH; Tyonek A is driven by copper. For the acute mixing zones, the driving parameters varied

between copper, silver, and zinc. Based on the data collected for site specific mixing zone analysis and various Cook Inlet water quality studies, the following sections describe specifics of each analysis in relation to driving parameters, size, and dilution factors. Figure 3 through Figure 10 depicts the alignment based on the main axis of prevailing ebb and flood currents.

6.2.3.6.1 TBPF

During the term of the 2007 GP, TBPF installed a diffuser that significantly improved mixing of the produced water discharge in the receiving water. Based on evaluation of recent data described in Section 4.6.4.1, the driving parameter for the chronic mixing zone is TAH and copper for the acute mixing zone. A sensitivity analysis around observed stratification scenarios and percentile current speeds was conducted to determine the critical ebb and flood conditions driving the size of the chronic mixing zone boundary. The result of the sensitivity analysis was the 30th percentile and the lowest observed pycnocline height controlled the ebb and the 10th percentile current and a linear stratification controlled the flood. Based on meeting water quality criteria for these driving parameters at the boundary of their respective mixing zone boundary, DEC authorizes rectangular acute and chronic mixing zones that extend from the sea surface to the seafloor centered asymmetrically and aligned according to the drogue tracks observed during the ICIEMAP data collection. The dimensions of the chronic mixing zone shown in Figure 3 are 4,521 meters long (3,124 meters ebb and 1,397 meters flood) by 1,872 meters wide. The dimensions of the acute mixing zone (not shown) are 2 meters long by 81 meters wide centered symmetrically about the diffuser. The authorized chronic dilution factor is 1,335 and the acute is 4.5.

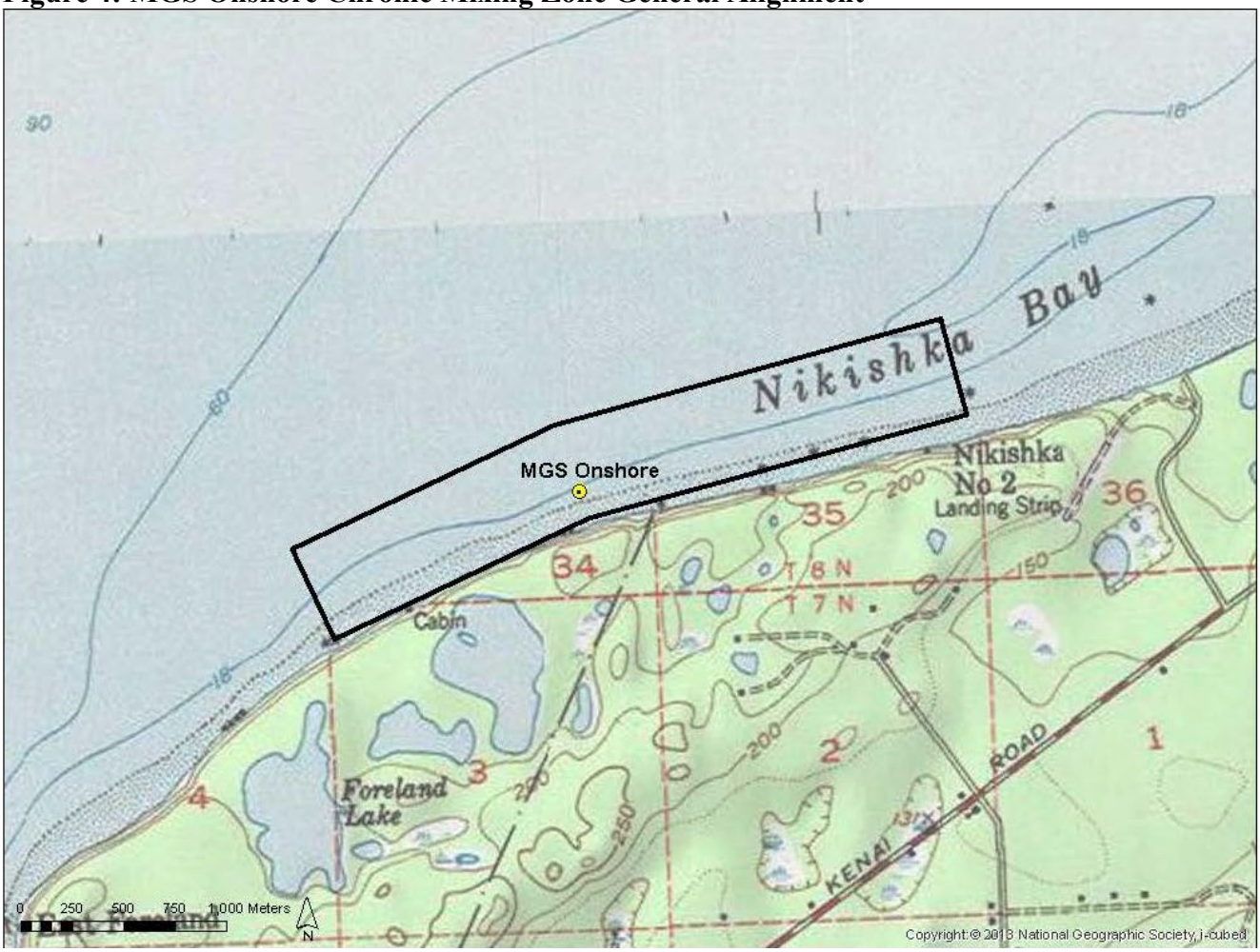
Figure 3: TBPF Chronic Mixing Zone General Alignment



6.2.3.6.2 MGS Onshore

Based on evaluation of recent data described in Section 4.6.4.2, the driving parameter for the chronic mixing zone is TAH and silver for the acute mixing zone. Sensitivity analysis of the discharge for MGS Onshore led to the determination that the 30th percentile current is the reasonable worst case condition. Based on the meeting water quality criteria for these driving parameters at the boundary of their respective mixing zone boundary, DEC authorizes a polygonal acute and chronic mixing zones that extend from the sea surface to the seafloor centered asymmetrically and aligned with the prevailing current directions determined using NOAA data. The dimensions of the chronic mixing zone shown in Figure 4 are 3,299 meters long (1,381 meters ebb and 1,918 meters flood) by 483 meters wide (142 meters toward shore and 341 meters away from shore). To evaluate the width offset of the plume, the assumption was made that the base main axis of the prevailing currents are parallel to the shoreline then the axis of the ebb and flood current directions were adjusted toward and away from the shoreline using CORMIX. The flood swing for the 30th percentile current is 36 degrees and 48 degrees for the ebb. An angle increment of 10 degrees away from the shoreline and a 4 degree increment toward the shore was determined to be the reasonable worst case condition. The dimensions of the acute mixing zone (not shown) are 115 meters long (48 meters ebb and 67 meters flood) by 27 meters (9 meters toward shore and 19 meters away) in the same alignment as the chronic mixing zone. The authorized chronic dilution factor is 2,180 and the acute is 21.5.

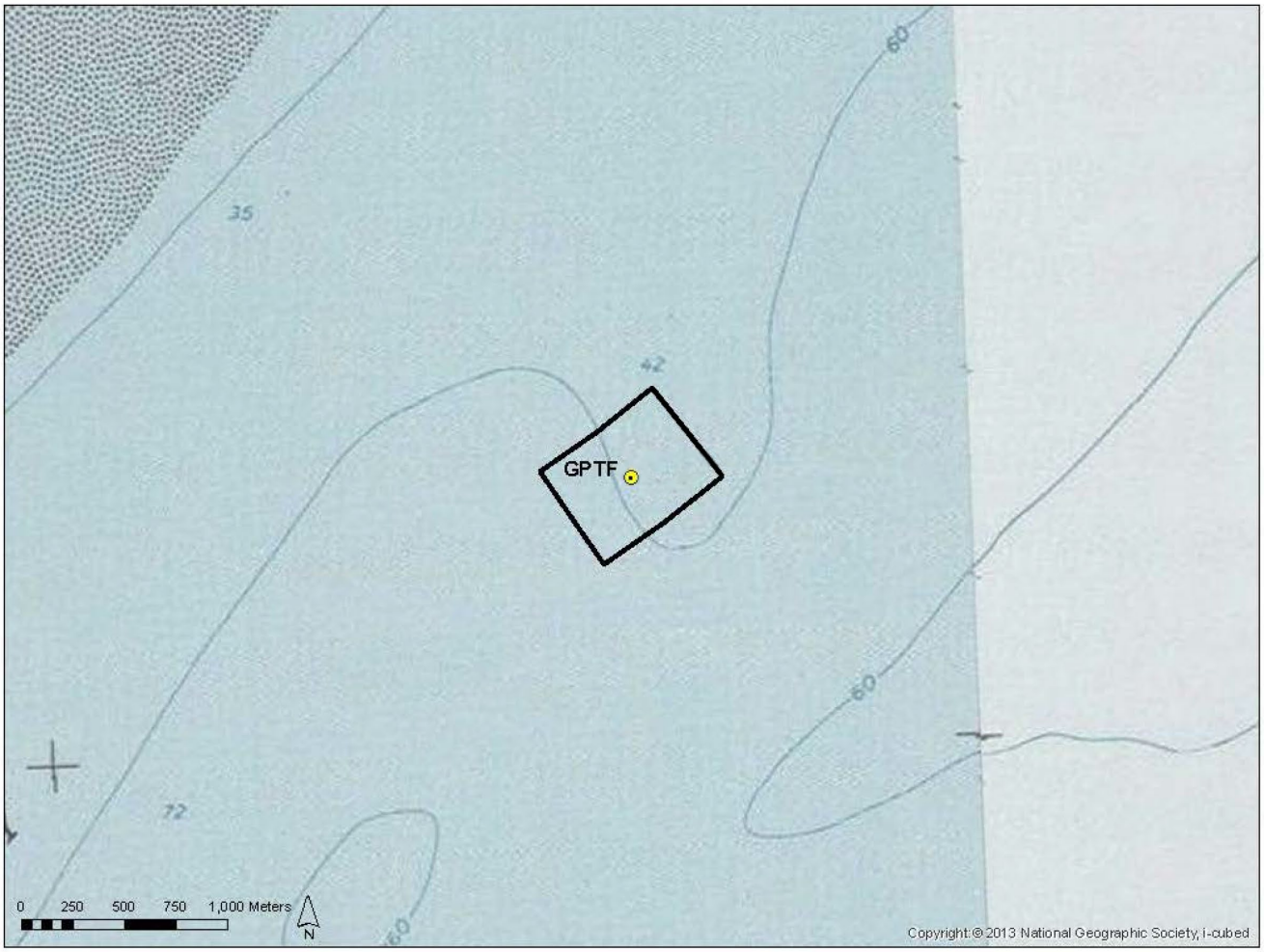
Figure 4: MGS Onshore Chronic Mixing Zone General Alignment



6.2.3.6.3 GPTF

Based on evaluation of recent data described in Section 4.6.4.3, the driving parameter for the chronic mixing zone is TAH and copper for the acute mixing zone. Based on meeting water quality criteria for these driving parameters at the boundary of their respective mixing zone boundary, DEC authorizes a polygonal acute and chronic mixing zones that extend from the sea surface to the seafloor centered on the discharge port but aligned according to prevailing current directions evaluated using nearby NOAA stations. The dimensions of the chronic mixing zone shown in Figure 5 are 698 meters long (294 meters each current direction) by 546 meters wide. The width of the chronic mixing zone was determined by examining the applicable range of current direction representing the 10th percentile current at the intersection of the length direction. The dimensions of the acute mixing zone (not shown) are 4 meters long by 4 meters wide centered symmetrically about the discharge port. The authorized chronic dilution factor is 2,175 and the acute is 11.5.

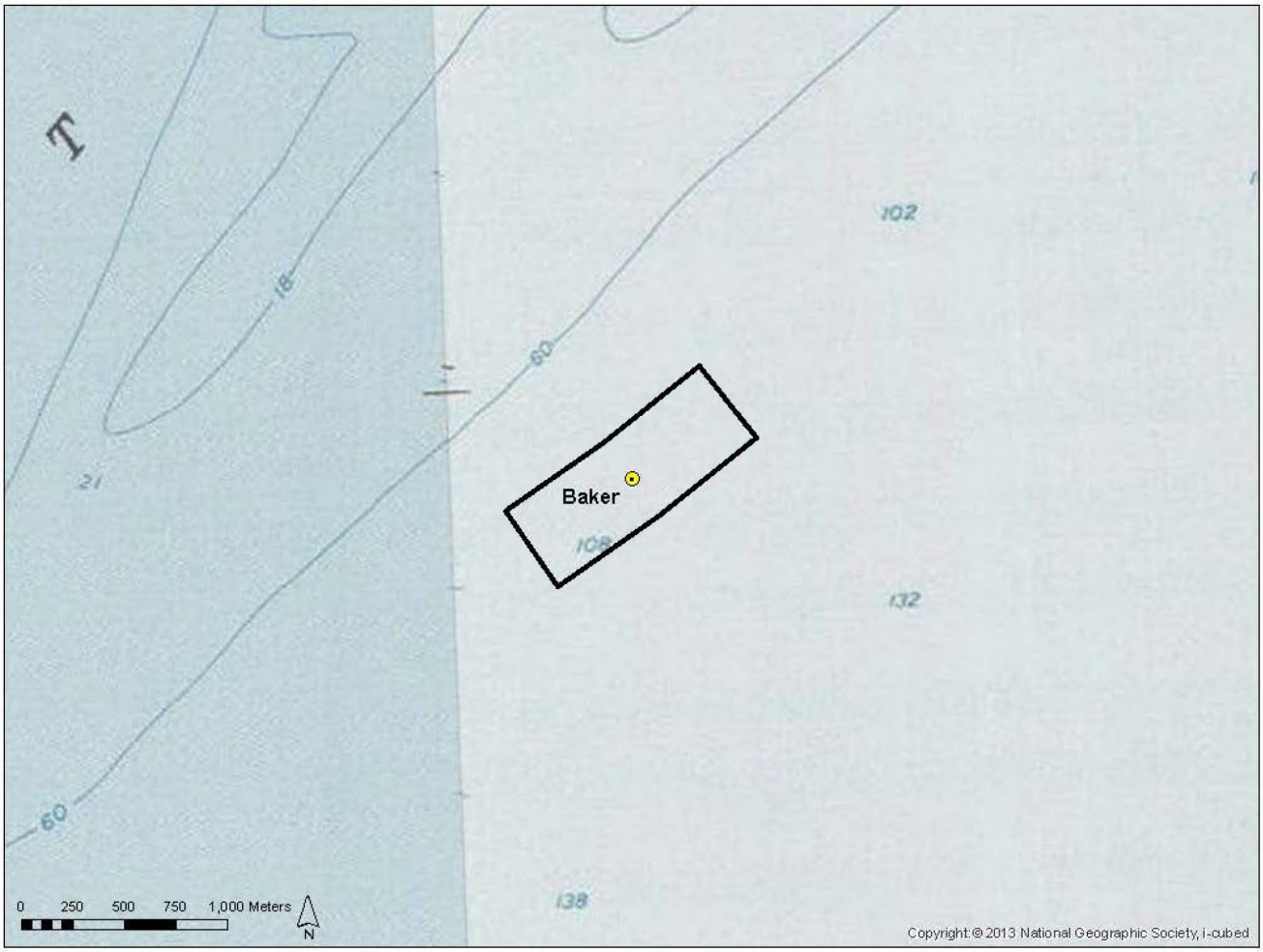
Figure 5: GPTF Chronic Mixing Zone General Alignment



6.2.3.6.4 Baker Platform

Based on evaluation of recent data described in Section 4.6.4.4, the driving parameter for the chronic mixing zone is TAH and zinc for the acute mixing zone. Based on the meeting water quality criteria for these driving parameters at the boundary of their respective mixing zone boundary, DEC authorizes a polygonal acute and chronic mixing zones that extend from the sea surface to the seafloor centered on the discharge port but aligned according to prevailing current directions evaluated using nearby NOAA stations. The dimensions of the chronic mixing zone shown in Figure 6 are 1,188 meters long (594 meters each current direction) by 444 meters wide. The width of the chronic mixing zone was determined by examining the applicable range of current direction representing the 10th percentile current at the intersection of the length direction. The dimensions of the acute mixing zone (not shown) are 86 meters long by 28 meters wide centered on the discharge port and aligned the same as the chronic mixing zone. The authorized chronic dilution factor is 3,390 and the acute is 134.

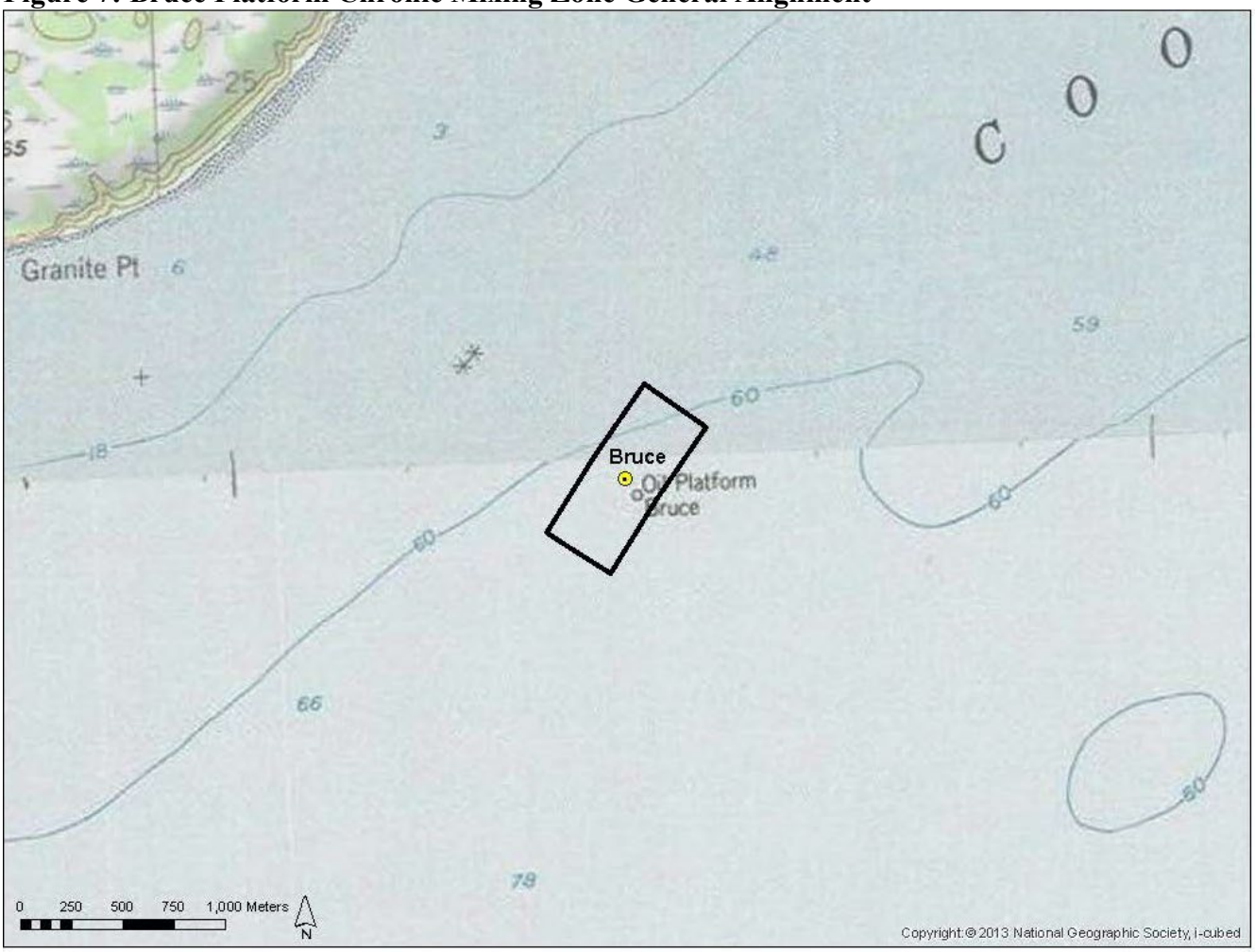
Figure 6: Baker Platform Chronic Mixing Zone General Alignment



6.2.3.6.5 Bruce Platform

Based on evaluation of recent data described in Section 4.6.4.5, the driving parameter for the chronic mixing zone is TAH and zinc for the acute mixing zone. Based on the meeting water quality criteria for these driving parameters at the boundary of their respective mixing zone boundary, DEC authorizes a polygonal acute and chronic mixing zones that extend from the sea surface to the seafloor centered on the discharge port but aligned according to prevailing current directions evaluated using nearby NOAA stations. The dimensions of the chronic mixing zone shown in Figure are 860 meters long (430 meters each current direction) by 370 meters wide. The width of the chronic mixing zone was determined by examining the applicable range of current direction representing the 10th percentile current at the intersection of the length direction. The dimensions of the acute mixing zone (not shown) are 160 meters long by 62 meters wide centered on the discharge port and aligned the same as the chronic mixing zone. The authorized chronic dilution factor is 3,395 and the acute is 268.

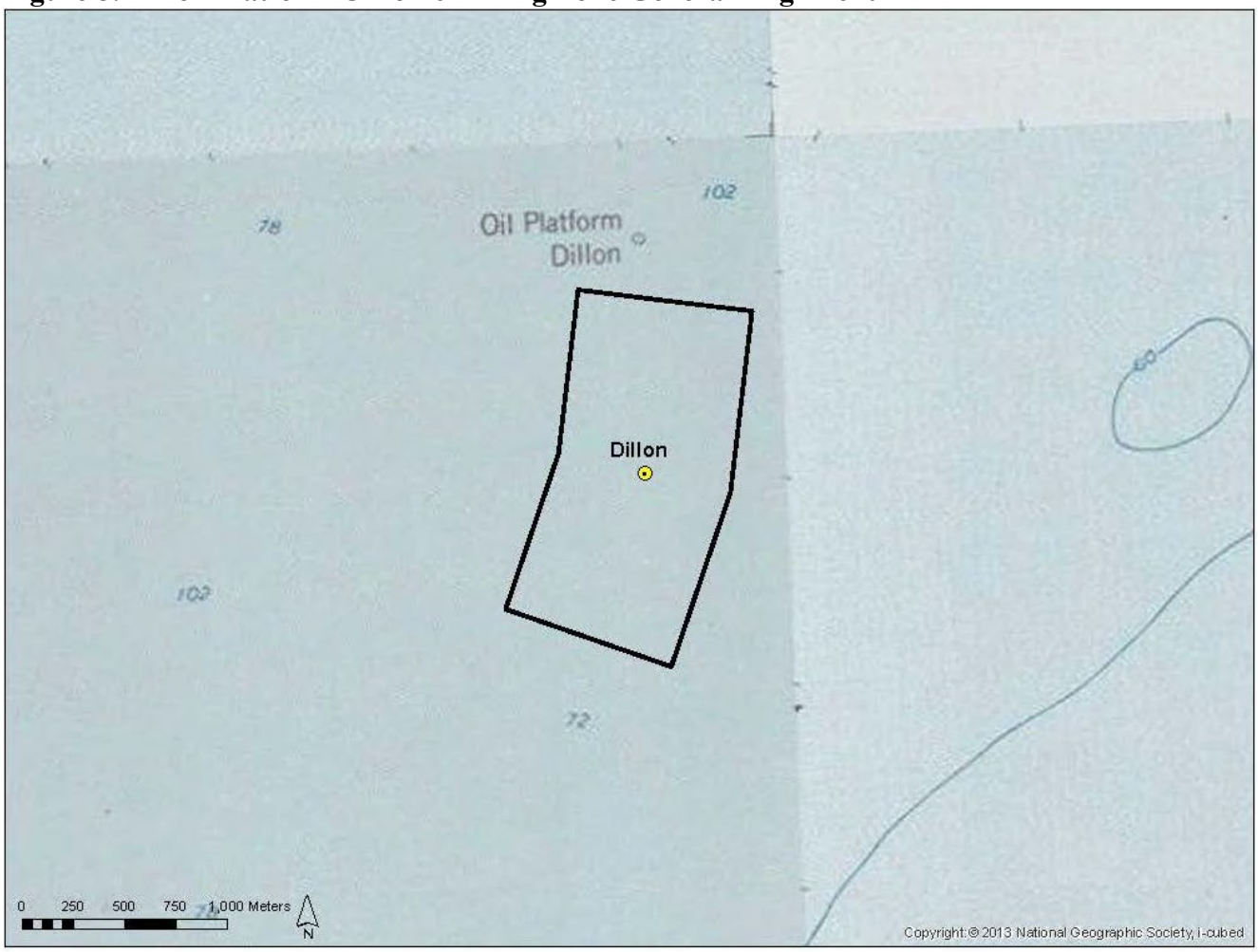
Figure 7: Bruce Platform Chronic Mixing Zone General Alignment



6.2.3.6.6 Dillon Platform

Based on evaluation of recent data described in Section 4.6.1, the driving parameter for the chronic mixing zone is TAH and silver for the acute mixing zone. Based on the meeting water quality criteria for these driving parameters at the boundary of their respective mixing zone boundary, DEC authorizes polygonal acute and chronic mixing zones that extend from the sea surface to the seafloor centered on the diffuser but aligned according to prevailing current directions evaluated using nearby NOAA stations. The dimensions of the chronic mixing zone shown in Figure are 1,690 meters long (845 meters each current direction) by 856 meters wide. The width of the chronic mixing zone was determined by examining the applicable range of current direction representing the 10th percentile current at the intersection of the length direction. The dimensions of the acute mixing zone (not shown) are 20 meters long by 14 meters wide centered on the diffuser and aligned the same as the chronic mixing zone. The authorized chronic dilution factor is 3,390 and the acute is 21.5.

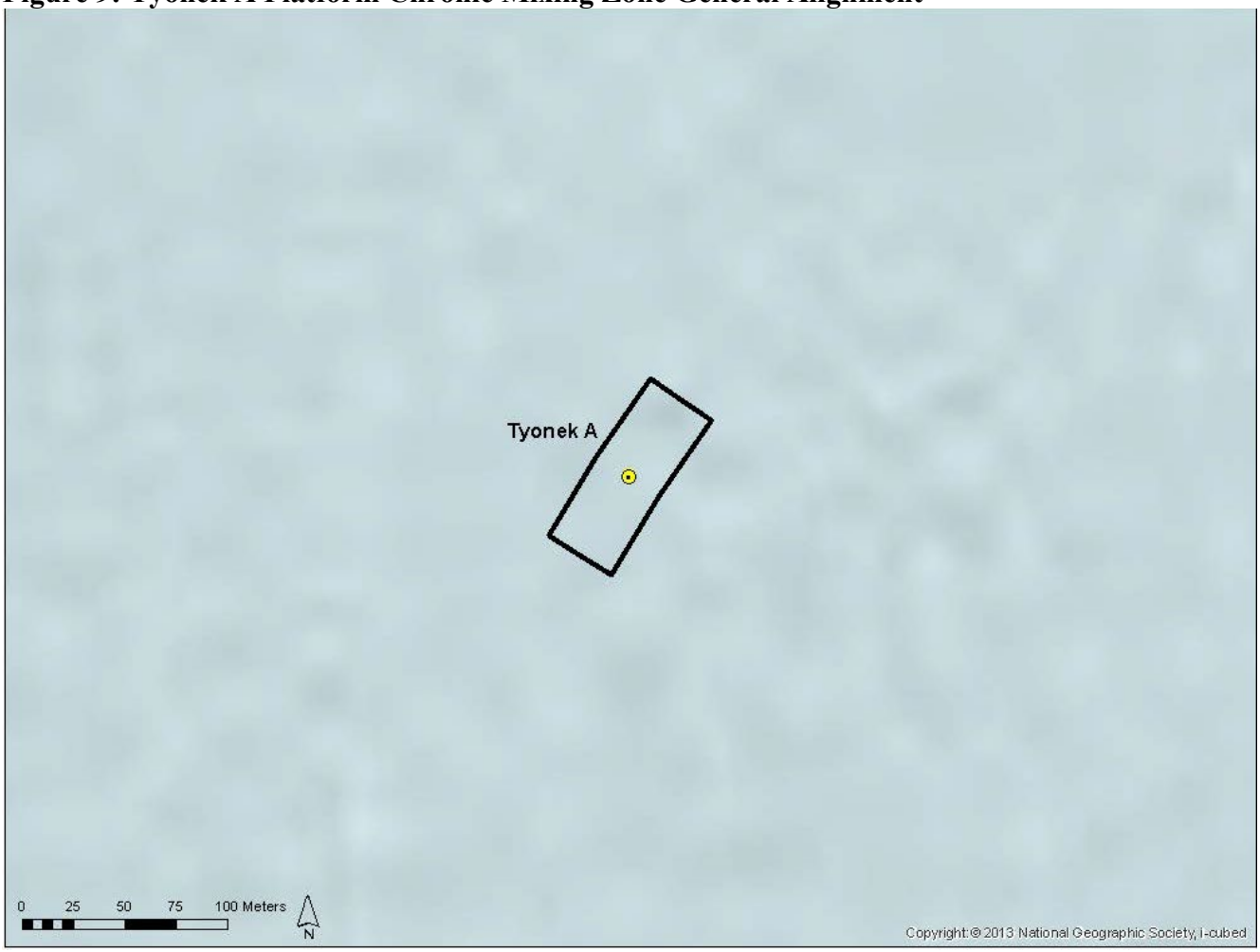
Figure 8: Dillon Platform Chronic Mixing Zone General Alignment



6.2.3.6.7 Tyonek A Platform

Based on evaluation of recent data described in Section 4.6.1, the driving parameters for the both the chronic mixing zone and acute mixing zone is copper. Based on the meeting water quality criteria for these driving parameters at the boundary of their respective mixing zone boundary, DEC authorizes polygonal acute and chronic mixing zones that extend from the sea surface to the seafloor centered on the diffuser but aligned according to prevailing current directions evaluated using nearby NOAA stations. The dimensions of the chronic mixing zone shown in Figure are 90 meters long (45 meters each current direction) by 36 meters wide. The width of the chronic mixing zone was determined by examining the applicable range of current direction representing the 10th percentile current at the intersection of the length direction. The dimensions of the acute mixing zone (not shown) are 22 meters long by 17 meters wide centered on the diffuser and aligned the same as the chronic mixing zone. The authorized chronic dilution factor is 280 and the acute is 160.

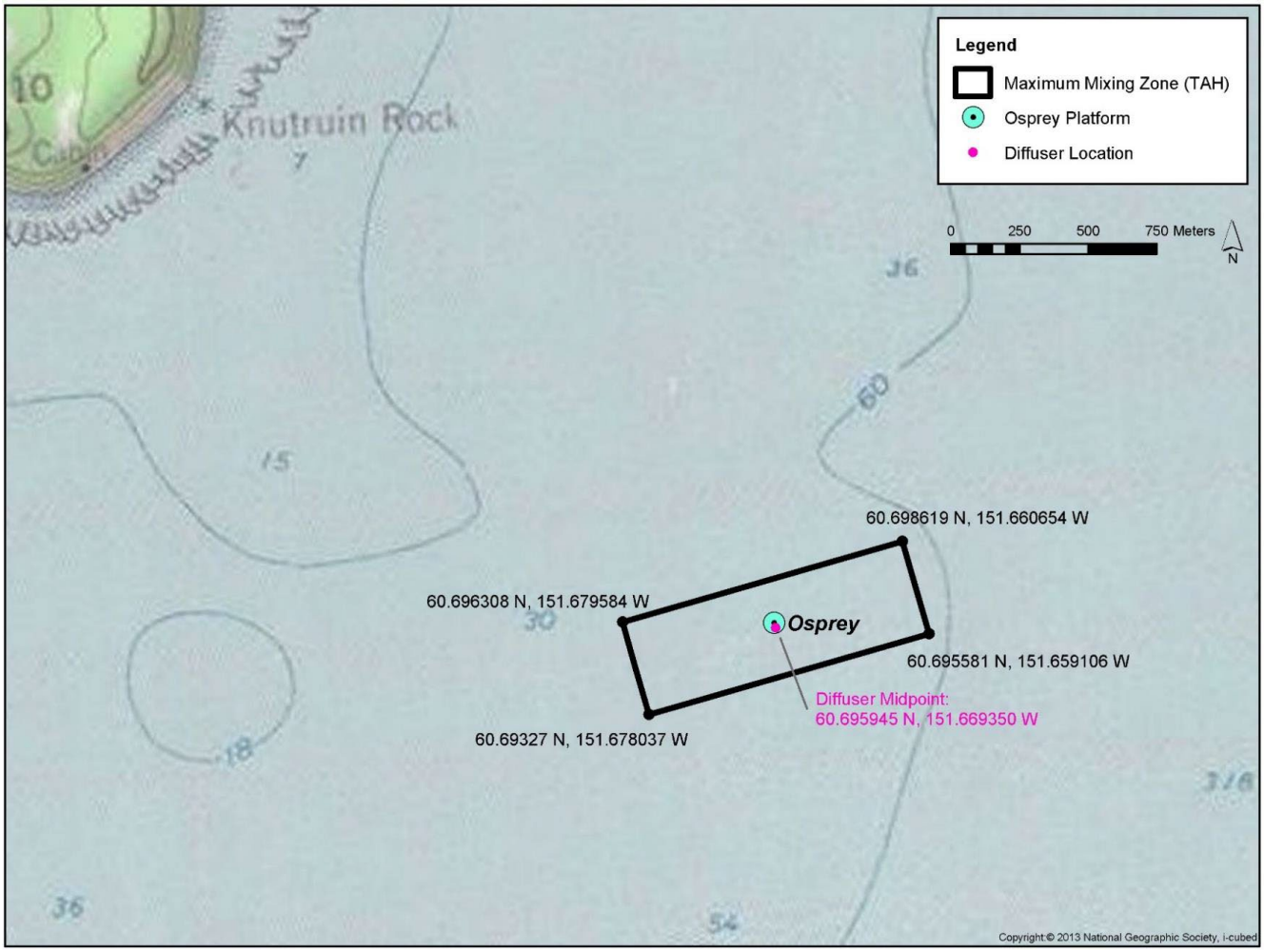
Figure 9: Tyonek A Platform Chronic Mixing Zone General Alignment



6.2.3.6.8 Osprey Platform

Based on evaluation of recent data described in Section 4.6.1, the driving parameters for the both the chronic mixing zone and acute mixing zone is copper. Based on the meeting water quality criteria for these driving parameters at the boundary of their respective mixing zone boundary, DEC authorizes rectangular acute and chronic mixing zones that extend from the sea surface to the seafloor centered on the diffuser and aligned according to prevailing current directions evaluated using nearby NOAA stations. The dimensions of the chronic mixing zone shown in Figure are 1,060 meters long (438 meters each current direction) by 348 meters wide. The width of the chronic mixing zone was determined by examining the applicable range of current direction representing the 10th percentile current at the intersection of the length direction. The dimensions of the acute mixing zone (not shown) are 13 meters long by 13 meters wide centered on the diffuser and aligned the same as the chronic mixing zone. The authorized chronic dilution factor is 800 and the acute is 40.

Figure 10: Osprey Platform Chronic Mixing Zone General Alignment



6.2.3.6.9 Mixing Zones for Produced Water Discharges

6.2.3.6.10 Produced Water Mixing Zone Summary

Per 18 AAC 70.255(a-c), the size of the mixing zone must ensure water quality criteria is met at the boundary of the mixing zone and may not cause, or reasonably be expected to cause, lethality to passing organisms, or a toxic effect in the water column, sediments, or biota outside the boundaries of the mixing zone. Hence, the mixing zone must be sized conservatively to ensure human health and aquatic life criteria are met at the boundary of the chronic mixing zone. Except for Tyonek A, the size of the chronic mixing zone is based on meeting the stringent chronic water quality criteria for TAH. As demonstrated through characterization of chronic toxicity of produced water in Section 4.6.5, TAH several factors to orders of magnitude more stringent when compared to chronic toxicity results for Cook Inlet produced water discharges. Because the TAH stringent criteria must be met at the chronic mixing zone boundary, produced water mixing zones tend to reflect this stringent, conservative, approach required by regulation. Furthermore, by meeting the evaluation requirements under 18 AAC 70.240 through 70.270, mixing zones are inherently small as practicable.

The mixing zone analysis used new information, included sensitivity analysis to increase certainty, and included an extensive evaluation of effluent and receiving water data to improve upon previous mixing zone evaluations. While it may have been envisioned that a more robust mixing zone analysis would lead to smaller mixing zones, the result may be contrary to this vision due to regulatory requirements. However, as discussed in other

sections of this Fact Sheet, increases in mixing zone sizes do not mean that pollutant loads under the Permit have increased. Table 27 provides a comparison between the authorized chronic and acute mixing zones dilution factors ($DF_{a,c}$) and corresponding mixing zone lengths (L) and widths (W) from the 2007 GP to that in the current Permit.

Table 27: Comparison of Current Mixing Zone Dimensions to 2007 GP Dimensions

Facility	$DF_{a,c}$ L x W (m)	2007 GP		Current Permit	
		Chronic	Acute	Chronic	Acute
TBPF	$DF_{a,c}$	1,970	20.3	1,335	4.5
	L x W	2,418 x 360	< 1 x 80	4,521 x 1,872	2 x 81
MGS Onshore	$DF_{a,c}$	2,556	64.6	2,185	21.5
	L x W	1,749 x 8	142 x 1	3,299 x 483	115 x 27
GPTF	$DF_{a,c}$	7 756	32.2	2,178	21.5
	L x W	2,685 x 20	19 x 1	698 x 546	4 x 4
Baker	$DF_{a,c}$	15,668	151	3,390	134
	L x W	3,016 x 6.6	202 x 26	1,188 x 444	86 x 28
Bruce	$DF_{a,c}$	9,170	496	3,400	267.5
	L x W	1,840 x 11	201 x 26	860 x 370	160 x 62
Dillon	$DF_{a,c}$	9,986	24	3,392	21.5
	L x W	2,121 x 6.6	11 x 1	1,690 x 856	20 x 14
Tyonek A	$DF_{a,c}$	175.6	178.7	156	90
	L x W	60 x 1	36 x 1	90 x 36	22 x 17
Osprey	$DF_{a,c}$	--	--	800	64
	L x W	--	--	1060 x 438	13 x 13

6.2.3.7 Well Completion (Discharge 016), Workover (Discharge 017), Treatment (Discharge 018), and Test Fluids (Discharge 019)

Well Completion Fluids (016), Workover Fluids (Discharge 017), Well Treatment Fluids (018), and Well Test Fluids (019) contain formation fluids and chemical additives that were inject downhole that could elevate chronic toxicity and dissolved hydrocarbons, TAH and TAqH. In addition, pH is also included due chemical use and adoption of a TBEL using case-by-case BPJ of no less than 6.0 and no greater than 9.0 (See Appendix C). Accordingly, the discharge of these fluids requires a standard 100 meter chronic mixing zone to ensure respective water quality criteria are met at the boundary of the mixing zone per WQS.

6.2.4 Produced Water Mixing Zone Sizing

Because the produced water mixing zones represent the greatest portion of the allocated assimilative capacity under the Permit, DEC emphasizes the sizing of the produced water mixing zones and adds additional information to address the other mixing zones that represent a comparatively smaller allocation. Per 18 AAC 70.255(e)(1)(A) and (B), unless the Department finds that evidence is sufficient to reasonably demonstrate, in accordance with this section, that the size limitations of a mixing zone can safely be increased, a mixing zones must comply with the following size restrictions for estuarine and marine waters, measured at MLLW:

A. The cumulative linear length of all mixing zones intersected on any given cross section of the inlet may not exceed 10 % of the total length of that cross section, and

B. The total horizontal area allocated to all mixing zones may not exceed 10 % of the surface area.

DEC has mapped the mixing zones using GIS in order to evaluate the worst-case cross section that intersects the most produced water chronic mixing zones to evaluate what percentage of the linear length of that cross section intersects mixing zones. DEC also used GIS to evaluate the surface area of the coverage area of the Permit to compare to tabulated areas of the authorized produced water mixing zones to evaluate the percentage of allocated area. The total linear length of the critical cross section is 53,113 meters (33 miles) and the cumulative linear length of the intersected mixing zones is 5,816 (3.6 miles), which results in a percentage of 10.9 %. Figure 18 in Appendix A provides the critical transect used in this evaluation. Similarly, total area of coverage is 416,528 hectares (See Figure 1) and the total cumulative area calculated from Table 27 is 1,310 hectares, resulting in an allocated area percentage of 0.31 %. Although the linear evaluation is slightly above 10 %, the area evaluation is below the 10 percent restriction. Based on review of sufficient evidence pertinent to this section, DEC finds that the evidence reasonably demonstrates that linear size limitation can be safely increased.

Per 18 AAC 255(b), the mixing zone may not cause, or reasonably be expected to cause: 1) lethality to passing organisms, or 2) a toxic effect in the water column, sediments, or biota outside the boundaries of the mixing zones. Lethality to passing organisms is not expected to occur when considering the largest acute mixing zone authorized, 80 meters in for the Bruce, and the 10th percentile current speed of 0.3 m/s. For these conditions, a passing organism would be in the largest authorized acute mixing zone for less than 4.5 minutes, which lower than the 15 minutes typically used to determine lethal exposure in this scenario. Aside from produced water, the only other discharges with acute mixing zones include domestic wastewater and graywater. These mixing zones are 17 meters and are significantly smaller than the largest produced water acute mixing zone evaluated. The determination of toxic effects in the water, sediments or biota for all authorized mixing zones, see Section 6.2.8.

Per 18 AAC 70.255(C), human health and chronic aquatic life criteria apply at the boundary of the chronic mixing zone. All chronic mixing zones authorized under the Permit have been sized to ensure chronic aquatic life criteria and human health criteria are met at the boundary of each chronic mixing zone. See Section 6.2.10for aquatic life and Section 6.2.8for human health.

Based on the evaluation of sufficient evidence, DEC concludes that the linear size restriction can safely be increased. This conclusion considered the implications of all other mixing zones in the area of coverage that were not specifically discussed

6.2.5 **Technology**

Per 18 AAC 70.240(a)(3), the Department must determine if "an effluent or substance will be treated to remove, reduce, and disperse pollutants, using methods found by the department to be the most effective and technologically and economically feasible, consistent with the highest statutory and regulatory treatment requirements" prior to authorizing a mixing zone.

Applicable "highest statutory and regulatory requirements" are defined in 18 AAC 70.990(30) [2003]. Accordingly, there are three parts to the definition, which are:

- Any federal TBEL identified in 40 CFR 125.3 and 40 CFR 122.29, as amended through August 15, 1997, adopted by reference at 18 AAC 83.010;
- Minimum treatment standards in 18 AAC 72.040; and
- Any treatment requirement imposed under another state law that is more stringent than the requirement of this chapter.

6.2.5.1 TBELs

The first part of the definition includes all applicable TBELs based on ELGs or TBELs developed using case-by-case best professional judgment (BPJ). DEC is relying, in part, on

the ELGs for the Oil and Gas Extraction Point Source Category per 40 CFR 435 Subpart D (Coastal Subcategory adopted by reference at 18 AAC 83.010(g)(3). These ELGs are applicable to the discharges of drilling fluids and drill cuttings from oil and gas exploration, development, and production drilling; deck drainage; domestic wastewater; graywater; produced water; and well treatment, workover, and completion fluids.

The limits for the discharge of drilling fluids and drill cuttings (Discharge 001) include SPP toxicity, surrogate metals cadmium and mercury, no discharge of diesel, and no discharge of free oil by the Static Sheen Test. The ELGs for deck drainage (Discharge 002) also requires no discharge of free oil as determined. The ELGs for Domestic Wastewater (003) require no floating solids and TRC concentrations to be a minimum of 1.0 mg/L and to be maintained as close to this concentration as possible for facilities continuously manned by 10 or more persons (M10). For graywater (Discharge 004), the ELG require no floating solids, foam, or garbage. The ELGs for produced water establish an MDL of 42 mg/L for oil and grease and an AML of 29 mg/L. For well completion, workover, and completion Fluids (Discharges 016, 017, and 018) the ELGs require the same limitations as produced water.

DEC has also established several TBELs using case-by-case BPJ. Fire control test water; noncontact cooling water; excess cement slurry; drilling fluids, cuttings, and cement at the seafloor is limited to no discharge of free oil. The Permit establishes a maximum daily limit for TRC of 1.0 mg/L using case-by-case BPJ citing dechlorination as an effective and technologically and economically feasible treatment to attain this limit. Well completion, workover, treatment, and test fluids also have no free oil plus pH limitations. Test fluids are not included in the ELGs. DEC is imposing the limitations from the ELG for well treatment, workover, and completion fluids to test fluids using case-by-case BPJ.

Discharges of drilling fluids and drill cuttings associated with non-oil and gas drilling has been added to the Permit for conducting geotechnical surveys and HDD. When barite is a component in the drill fluid system (Class C3 Drilling Fluids), DEC imposes limits for mercury, 1 mg per kilogram (mg/kg), and cadmium, 3 mg/kg, using case-by-case BPJ citing 40 CFR 435 as the basis.

6.2.5.2 Minimum Treatment

The second part of the definition from the WQS appears to be in error, as 18 AAC 72.040 considers discharge of sewage to sewers and not minimum treatment. The correct reference appears to be 18 AAC 72.050, minimum treatment for domestic wastewater. As discussed in Section 3.5.4.1, any domestic wastewater discharge, treated black water (Discharge 003) or graywater (Discharge 004), that does not meet minimum treatment, must obtain a waiver even if the limits themselves are less stringent than secondary standards. As discussed in Section 3.5.4.2, the Anna, Bruce, and Dillon were granted waivers via previous CWA 401 Certification. In addition, Randolph Yost MODU received a waiver for secondary treatment for Discharge 003 – Domestic Wastewater on April 22, 2016 and the Spartan 151 received a waiver to secondary treatment for Discharge 004 – Graywater on February 20, 2018. Graywater is domestic wastewater that requires at least primary treatment and waiver to secondary treatment (18 AAC 72.060) to be discharge under the Permit. Any new domestic wastewater system that seeks coverage under the Permit must meet the requirements of the most recent version of 18 AAC 72.

The third part of the definition includes any treatment required by state law that is more stringent than 18 AAC 70. Other regulations beyond 18 AAC 70 that may apply to this permitting action include 18 AAC 83, 18 AAC 72 and 18 AAC 15. The Permit limitations, prohibitions, and BMP requirements are consistent with both 18 AAC 83 and 18 AAC 70. The application of 18 AAC 72 is discussed in the preceding paragraph. Neither the regulations in 18 AAC 15 nor another state legal requirement that the Department is aware

of impose more stringent treatment requirements than 18 AAC 70 other than 18 AAC 72. DEC finds that the requirement for technology has been met.

6.2.6 Existing Use

Per 18 AAC 70.245, the mixing zone has been appropriately sized to fully protect the existing uses of Cook Inlet. Water quality criteria are developed to specifically protect the uses of the waterbody as a whole. When applying criteria, DEC uses the most stringent criteria among the various use classes. Therefore, if the water quality criteria are met in the waterbody, then the existing uses are protected. Given that all authorized mixing zones have been sized to ensure all water quality criteria will be met at, and beyond, the boundary of the chronic mixing zone, the existing uses beyond the boundary of the chronic mixing zone will be maintained and fully protected under the terms of the Permit as required in 18 AAC 70.245 (a)(1) and (a)(2).

6.2.7 Human Consumption

Per 18 AAC 70.250(b)(2) and (b)(3), the subject pollutants will not produce objectionable color, taste, or odor in aquatic resources harvested for human consumption, nor will the discharge preclude or limit established processing activities or commercial, sport, personal use, or subsistence fish and shellfish harvesting. Compliance with permit conditions will regulate discharge of pollutant concentrations so that the discharges will not produce objectionable color, taste, or odor in aquatic resources.

The discharges will not preclude or limit established processing activities or commercial, sport, personal use, or subsistence fish and shellfish harvesting. Areas where these uses exist have either been excluded from the Permit coverage area due to proximity to the activity or due to depth restrictions. The Permit requires the applicant to submit information during the NOI or application process to ensure these conditions are met. Prior to authorizing a mixing zone, when the applicant identifies harvesting activities, DEC may deny the mixing zone or impose time-area restrictions during the authorization process as appropriate to ensure this requirement is met. The Department has determined that based on this coordination requirement the discharges are not expected to result in precluding or limiting established processing activities or commercial, sport, personal use, or subsistence fish and shellfish harvesting.

6.2.8 Human Health

Per 18 AAC 70.250(a)(1), 18 AAC 70.255(b) and (c), and 18 AAC 70.255(e)(3)(B) the mixing zones will not result in pollutants discharged at levels that will bioaccumulate, bioconcentrate, or persist above natural levels in sediments, water, or biota, or at levels that otherwise will create a public health hazard through encroachment on a water supply or contact recreation uses. The Department has reviewed currently available data that reasonably demonstrates bioaccumulation or bioconcentration is not occurring as a result of discharges authorized by the Permit. During the last permit cycle, sediment and water column studies were conducted to assess persistence of pollutants in the discharge associated with produced water and documented in the Produced Water Study (PWS) Report. The data collected is also pertinent to the discharge of drilling fluids and drill cuttings. Cook Inlet, is a very dynamic waterbody and constantly changing tidal velocities and directions cause a continuous reworking and scouring of fine-grained sediments in the vicinity of the discharge. The resulting bottom sediments in the mixing zone area are typically characterized as sands, gravels, and cobbles with minor fractions of silt and clay (0.6 to 1.2 %). Analysis of metals and hydrocarbons in these sediments indicate concentrations are well below published criteria (Long, 1993) and are indistinguishable from background sediment concentrations (Kent and Sullivan, 2005). When coarse-grained sediment is beneath the mixing zone, the propagation of shellfish or other benthic species are not expected to exist so are not considered to be a receptor for bioaccumulative pollutants at these locations.

The PWS Report developed under the 2007 GP indicated discharges related to oil and gas activities are not resulting in persistence in the environment. Major conclusions derived from these works include, but are not limited to:

- Concentrations of barium, cadmium, chromium, copper, nickel, lead, and zinc for bottom sediments in Cook Inlet were at background values at all 55 sampling stations.
- Concentrations of arsenic, manganese and selenium for bottom sediments in Cook Inlet were above background values at a few locations but could be caused by natural changes of rock and sediments.
- Concentrations of many metals in bottom sediments were below sediment quality guidelines that evaluate effects to bottom dwelling test organisms. (Note: Although Alaska WQS do not include specific sediment quality standards, these types of tests help to evaluate whether metals in the water column are concentrating at levels in sediments that can impact aquatic organisms directly or through the food web.)
- Mercury concentrations for bottom sediments in Cook Inlet were above background at 10 of 55 locations, including five in Kachemak Bay. (Note: Global sources of mercury discharges, including aerial deposition from combustion sources, impact waterbodies world-wide. The 2007 GP and the Permit prohibit discharges into Kachemak Bay.)
- Concentrations of dissolved metals in marine waters were comparable to background and no elevations of dissolved metals from produced water could be identified.
- Concentrations of dissolved metals in Cook Inlet rivers were variable and probably a function of both natural and man-induced sources.

Data on persistence in biota has been review for species at several trophic levels including fish, sea otters, and beluga whale. As described in the 2009 ATSDR, Health Consultation Study, contaminant concentrations detected in fish in Cook Inlet are similar to those in fish collected throughout Alaska (ATSDR 2009). The Alaska Department of Health and Social Services, Division of Public Health recommends that the majority of Alaskans continue unrestricted consumption of all fish from Alaskan waters, including those from Cook Inlet (DHSS 2007 and 2014). Contaminant levels in marine mammals have been reviewed, focusing on Sea Otters, Stellar Sea Lions, and Beluga Whales. The 2013 USFWS Recovery Plan for Sea Otters notes that "heavy metals are unlikely to be a casual factor in the decline" in sea otter populations in and around the Cook Inlet. Similarly, the 2008 Stellar Sea Lion recovery plan does not include oil and gas activities or related discharges as a threat to the population. The concentration of contaminants found in Cook Inlet Beluga Whales were lower than in other surveyed Alaskan beluga stocks, and the Cook Inlet population was actually healthier than most other national and international populations (Becker et al. 2000; Lebeuf et al. 2004; NFMS 2008a; Becker 2009; DFO 2012, Reiner et al. 2011; Wetzel et al.2010; Hoget et al. 2013). The comparatively low levels of contaminants documented in Cook Inlet belugas themselves as well as the low levels of contaminants in Cook Inlet water and sediment suggests the relative concern of contaminants, including those from oil and gas discharges, is low (NOAA 2016).

Per 18 AAC 70.250 and 18 AAC 70.255, the mixing zones authorized by the Permit shall be protective of human health. An analysis of available information reasonably demonstrates that the authorized mixing zone will protect human health. Per 18 AAC 70.255(c), human health criteria must be met at the boundary of the chronic mixing zone. Unlike aquatic life criteria that have short exposure periods, human health criteria are based on much longer exposure periods (e.g., lifetime exposure). Therefore, when assessing human health criteria at the boundary of the chronic mixing zone, it is appropriate to consider average effluent and receiving water conditions commensurate with the long exposure periods for which the human health criteria are based. To illustrate this point, the Department considered the low, long-term average

concentration of mercury in the mixing zone during the modeling efforts to derive the required dilution factor and distance to meeting the human health criteria. Mercury was selected at the surrogate because the criteria is most stringent, 0.051 µg/L, among the human health POCs authorized in the mixing zones. Table 28 provides a comparison of the dilution factors and mixing dimensions required to meet the mercury human health criteria with that of the chronic mixing zones where the human health criteria actually apply.

Table 28: Comparison of Mixing Zone Sizes and Dilution Factors for Meeting Human Health and Chronic Criteria

Criteria	$DF_{HH,c}$ L x W (m)	TBPF	MGS Onshore	GPTF	Baker	Bruce	Dillon	Tyonek A	Osprey
Human Health	DF_{HH}	< 1	6.5	1.57	7.6	12.1	13.9	6.5	< 1
	L x W (m)	--	3 x 1	1 x 1	58 x 12	2 x 1	14 x 5	1 x 1	--
Chronic	DF_c	1,335	2,185	2,178	3,390	3,400	3,390	156	827
	L x W (m)	4,521 x 1,872	3,299 x 483	698 x 546	1,188 x 444	860 x 370	1,690 x 856	90 x 36	1,060 x 530

The human health POCs in the effluent are at low concentrations, enabling human health criteria to be met within a short distance from the point of discharge. The resultant potential exposure period for aquatic organisms passing through the mixing zone is not sufficient to pose a risk to human health based on consumption. The Department considered the low, long-term average concentration of mercury in the mixing zone, the exposure period of fish (salmon) swimming through the plume, and the pathway of being consumed after harvest in areas typically outside the area of coverage. Given the low mercury concentrations and an understanding that salmon typically do not stay in the mixing zone long enough to bioaccumulate mercury, there is minimal potential for impacts to human health resulting from the discharge of low concentrations of mercury in the mixing zone. The Department has concluded that the available information reasonably demonstrates the discharge will not pose a human health risk when considering likely pathways of exposure and pollutant persistence in the vicinity of the discharge.

6.2.9 Spawning Areas

Per 18 AAC 70.225(h), a mixing zone is not authorized in an area of anadromous fish spawning or resident fish for spawning redds, Arctic grayling (*Thymallus arcticus*), northern pike (*Esox lucius*), inconnu/sheefish (*Stenodus leucichthys*) and all other whitefish in Alaska belonging to genera *Prosopium* and *Coregonus*, Arctic char (*Salvelinus alpinus*), Dolly Varden (*S. malma*), brook trout (*S. fontinalis*), rainbow trout (*Oncorhynchus mykiss*), cutthroat trout (*O.clarkii*), burbot Lota, landlocked coho salmon (*O. kisutch*), Chinook salmon (*O. tshawytscha*), and sockeye salmon (*O. nerka*). The Permit does not authorize the discharge of effluent to open waters of a freshwater lake, river, or other flowing freshwater. Therefore, there are no associated discharges to anadromous fish spawning areas or the resident freshwater fish listed in the regulation.

6.2.10 Aquatic Life

Per 18 AAC 70.255(b)(1) and (2), 18 AAC 70.250(b)(1), or 18 AAC 70.250(a)(2)(A-C) pollutants for which the mixing zones will be authorized will not result in concentrations outside of the mixing zone that are undesirable, present a nuisance to aquatic life, result in permanent or irreparable displacement of indigenous organisms, or a reduction in fish or shellfish population levels. Mixing zone authorizations result in water quality criteria being met at the boundary of the chronic mixing zones for all POCs. For domestic wastewater and graywater, establishing a 1 mg/L maximum daily limit for TRC for all facilities ensures the chronic life criteria is met at the chronic mixing zone boundary. For miscellaneous discharges involving chemically treated sea water, mixing zone authorizations for chronic WET are also contingent on chronic toxicity criteria being met at the boundary of the mixing zone. Coupled with the requirement for permittees to inventory chemical additives used to treat seawater, the Department determined WET monitoring coupled with PR BMP Revision Action Levels will ensure protection of aquatic life and indigenous organisms outside the mixing zone. The chronic mixing zones for produced water have been developed based on meeting stringent criteria for TAH at the boundary of facility-specific mixing zones to ensure protection of aquatic life beyond the boundary. New information and conservative modeling approaches have resulted in better assurance that criteria will be met at the boundary. The Department concludes that the discharges will meet all water quality criteria at and beyond the authorized mixing zone boundaries.

6.2.11 Endangered Species

Per 18 AAC 70.250(a)(2)(D), the mixing zone will not cause an adverse effect on threatened or endangered species. Based on the information regarding endangered species in the areas that are available to lease sales by DNR, as described in the 2013 ODCE and authorized under the Permit, authorized mixing zones are not likely to adversely affect threatened or endangered species. The Permit coverage area specifically excludes Type 1 Critical Habitat for the beluga whale. Although the coverage area includes Type 2 habitat for the beluga whale, the discharges are not likely to cause adverse effects to beluga whales migrating through these areas per coordination with the National Marine Fisheries Service (NMFS). Permittees must also address mitigation measures associated with exploration activities for endangered species when filing their Plan of Operations with DNR.

6.3 Zone Of Deposit

Per 18 AAC 70.210, the Department is authorizing a 100 meter radius zone of deposit for the discharge of Drilling Fluids and Drill Cuttings (001), Excess Cement Slurry (012) and, Fluids, Cement and Cuttings at the Seafloor (013). The Department evaluated the potential impacts from these deposits using technical information contained in various applications and DFPs, particularly as applied to 18 AAC 70.210(b)(1)-(6) and other available resources. For each of these discharges, the deposit will be composed of naturally occurring rock, sand and gravel cuttings from the borehole or similar coarse-grained material from cement slurry after the fine-grain fractions have been dispersed in the mixing zone. Some drilling fluids or cement may remain adhered to the coarse-grained deposits for short period of time. The characteristics of coarse-grained particles, including drilling fluids adhered to their surface, will have no direct or indirect impact on human health, will not bioaccumulate or persist in the environment (See Sections 4.1.2 and 6.2.8), or have impacts on aquatic life or other wildlife (See Section 6.2.10). Ensuring there is adequate dispersion in the receiving water by prohibiting discharges in shallow water and limiting the discharge rate will minimize potential adverse effects associated with the short-term zone of deposit.

Any fine-grained particles from cement or WBF that becomes suspended in the water column will meet all applicable water quality criteria at the boundary of the 100 meter chronic mixing zone (See Section 6.2.3.1). Accordingly, all uses of the waterbody are being protected beyond the boundary of the zone of deposit and chronic mixing zone. Due to the nature of cuttings and tidal movement of the natural gravel and sand sized sediments that may occur at various locations within the Permit coverage area, the deposit is anticipated to become intermixed with natural sediment over the course of several tidal cycles. In net erosional environments, the cuttings may exist on the seafloor for a short period corresponding with slack tide currents. The Department has determined the nature and duration of the deposit is not expected to adversely impact the receiving water or other uses of the waterbody beyond the boundary of the authorized zone of deposit. Based on this evaluation, the Department concludes that the requirements for authorizing a zone of deposit are met.

7.0 EFFLUENT LIMIT DEVELOPMENT

7.1 Basis for Permit Effluent Limits

The CWA requires that the limits for a particular pollutant be the more stringent of either TBEL or WQBEL. TBELs are set via EPA-rule makings in the form of ELGs and correspond to the level of treatment that is achievable using available technology. In establishing permit limits, DEC first determines which TBELs must be incorporated into the Permit. The applicable ELG TBEL requirements for the Permit are from 40 CFR 435 Subparts A and D, for the offshore and coastal applications. DEC evaluated the effluent quality expected to result from these technological controls to determine if the discharge could result in exceedances of the water quality criteria in the receiving water. If exceedances could occur, water quality-based effluent limits (WQBELs) must be included in the Permit.

18 AAC 83.015 prohibits the discharge of pollutants to waters of the US unless first obtaining a permit implemented by the APDES point source discharge program that meets the purposes of Alaska Statutes 46.03 and in accordance with CWA 402 and the requirements adopted by reference at 18 AAC 83.010. Per these statutory and regulatory provisions, the Permit includes effluent limits that require the discharger to (1) meet standards reflecting levels of technological capability, (2) comply with WQS, (3) comply with other state requirements that may be more stringent, and (4) cause no unreasonable degradation to the territorial seas and coastal waters.

The limits in the Permit reflect whichever requirements (technology-based or water quality-based) are more stringent. The Permit contains TBELs per 40 CFR 435, TBELs developed using best BPJ, and WQBELs. Table 29 below provides a summary of the limits that are applied to each discharge, with additional detail provided in the section below and Appendix C.

Table 29: Summary of Basis of Limits per Discharge Category

Discharge (Number)		TBELs		WQBELs
		ELGs	BPJ	
Class B Drilling Fluids and Drill Cuttings (DF/DC) (001)	WBF	Mercury (Hg) and Cadmium (Cd) Stock Barite SPP Toxicity LC_{50} Limit No Discharge Free Oil/Static Sheen Test No Diesel	--	--
	NAF	Hg and Cd Stock Barite Limits SPP Toxicity LC_{50} Limit No Discharge Free Oil/Static Sheen Test No Discharge Diesel No Discharge NAF Polynuclear Aromatic Hydrocarbon Mass Ratio Sediment 10-day Toxicity Biodegradation Rate Sediment 4-day Toxicity No Discharge Formation Oil Mass Ratio C_{16} – C_{18} NAF Retained on Cuttings Mass Ratio C_{12} – C_{14} NAF Retained on Cuttings	--	--
Class C DF/DC (001)	C1 & C2	--	--	Oil and Grease (O&G) (Sheen)
	C3	--	Hg and Cd Stock Barite	
Deck Drainage (002)		--	--	O&G (Sheen)
Domestic Wastewater (003)		TRC Minimum 1 mg/L (M10) No Floating Solids (M9IM)	BOD_5 and TSS MDL/AMLs TRC 1 mg/L MDL	--
Graywater (004)		No Floating Solids, Foam, Garbage	TRC 1 mg/L MDL (MSDs Only)	O&G (Sheen)
Misc. Discharges (005 – 014)		--	--	O&G (Sheen)
Produced Water (015)		O&G MDL/AML of 42/29 mg/L	6.0 < pH < 9.0	O&G (Sheen) Platforms Only
Well Treatment, Workover, & Completion Fluids (016 – 018)		O&G MDL/AML of 42/29 mg/L	6.0 < pH < 9.0	O&G (Sheen)
Test Fluids (019)		--	6.0 < pH < 9.0 O&G MDL/AML of 42/29 mg/L	O&G (Sheen)
Hydrostatic Test Water (020)		--	--	6.5 ≤ pH ≤ 8.5 O&G (Sheen) TAH 10 µg/L TAqH 15 µg/L Turbidity 25 NTU

8.0 EFFLUENT LIMITATIONS AND MONITORING REQUIREMENT

Pollutants in discharges must be controlled by meeting numeric limits, narrative limitations, developing and implementing BMPs, or combinations thereof. When applying effluent limitations to commingled discharges, the more stringent effluent limitations apply to the commingled discharge. In general, all discharges, whether alone or in combination, must not make the water unfit or unsafe; cause a film, sheen, or discoloration on the water surface or adjoining shoreline; cause leaching of toxic or deleterious substance, or cause a sludge, solid, or emulsion to be deposited beneath or upon the water surface, water column, on the bottom, or adjoining shoreline.

Per 18 AAC 83.455, APDES permits require monitoring to determine compliance with effluent limits. Monitoring frequencies for compliance with limits are based on the nature and effect of the pollutant, as well as a determination of the minimum sampling necessary to adequately monitor facility performance. Monitoring may also be required to gather data to evaluate future effluent limits or to monitor effluent impacts on receiving water quality. The Permittee is responsible for conducting

monitoring and reporting the results to DEC as described in the Permit. The basis for effluent limit derivation is discussed in Appendix C. The following sections summarize the effluent limits and describe the monitoring required for each discharge.

8.1 Requirements for Drilling Fluids and Drill Cuttings (Discharge 001)

The discharge of non-aqueous fluids (NAF) is prohibited except for situations where such fluids adhere to drill cuttings at facilities within the Territorial Seas, as defined 40 CFR 435 (See Table 31 and noted Sections). Exemptions to the zero discharge of non-aqueous drilling fluids which adhere to drill cuttings based on technical limitations may be granted per 40 CFR 435, Appendix A of Subpart D Coastal Subcategory.

DEC developed a classification system that separates drilling fluids for oil and gas (Class B) from drilling fluids used in HDD or geotechnical (geotech) drilling projects (Class C). DEC further distinguished drilling fluids within these classes using tiers based on the number and type of ingredients in the fluids system and estimates, or measurements, of the maximum potential toxicity based on the SPP LC_{50}. This tiered classification system was described in Section 4.1.4. The following sections discuss the effluent limitations and monitoring requirements specific to this classification system.

8.1.1 Effluent Limitations and Monitoring Requirements for Class B Drilling Fluids and Drill Cuttings (Discharge 001).

For discussing effluent limitations, the Class B drilling fluids are broken down into WBFs (Class B1 and B2) and NAF (Class B3). The effluent limitations and monitoring requirements for Class B1 and B2 fluids are summarized in Table 30. Effluent limits and monitoring requirements for Class B3 (NAF-based systems) are summarized in Table 31

Table 30: Effluent Limitations and Monitoring Requirements for Class B1 and B2 and Drill Cuttings (Discharge 001)

Pollutant Parameter	Effluent Limitations	Monitoring Requirements	
	MDLs and AMLs	Measurement Frequency	Sample Type
Flow (mgd) [8.1.1.1]	Report	Monthly	Estimate
Depth Dependent Discharge Rates 0 to 5 meters [8.1.1.2] >5 to 20 meters >20 to 40 meters >40 meters	No discharge 500 barrels per hour (bbl/hr) 750 bbl/hr 1,000 bbl/hr	Continuous during discharge	Estimate
SPP toxicity 96 hour LC_{50} [8.1.1.3]	≥ 30,000 parts per million (ppm)	Monthly and End-of-Well (EOW)[8.1.1.7]	Grab
Free oil [8.1.1.4]	No discharge	Daily	Grab
Diesel oil [8.1.1.5]	No discharge	Daily	Grab
Mercury [8.1.1.6]	1 mg per kilogram (mg/kg)	Once per well	Grab
Cadmium [8.1.1.6]	3 mg/kg	Once per well	Grab

Table 31: Effluent Limitations and Monitoring Requirements for Class B3 Drilling Fluids and Drill Cuttings (Discharge 001)

Base Fluid [8.1.1.8] or Cuttings	Pollutant Parameter	Effluent Limitations	Monitoring Requirements	
		Average Monthly and Maximum Daily Limits	Measurement Frequency	Sample Type
NAF Stock Base Fluid	Volume (mgd) [8.1.1.1]	Report	Monthly	Estimate
	Mercury [8.1.1.6]	1 mg/kg	Annual	Grab
	Cadmium [8.1.1.6]	3 mg/kg	Annual	Grab
	Polynuclear Aromatic Hydrocarbons (PAH) [8.1.1.9]	mass ratio < $1x10^{-5}$	Annual	Grab
	Sediment toxicity ratio [8.1.1.10]	ratio < 1.0	Annual	Grab
	Biodegradation rate [8.1.1.11]	ratio < 1.0	Annual	Grab
NAF Adhered to Drill Cuttings	Volume (MG) [8.1.1.1]	Report	Monthly	Estimate
	Free Oil [8.1.1.4]	No discharge	Daily	Grab
	Diesel oil [8.1.1.5]	No discharge	Daily	Grab
	SPP toxicity 96 hour LC_{50} [8.1.1.3]	≥ 30,000 ppm	Monthly and EOW[8.1.1.7]	Grab
	Sediment toxicity ratio [8.1.1.12]	ratio < 1.0	Annual	Grab
	Formation oil [8.1.1.13]	No discharge	Daily	Grab
	C_{16}-C_{18} internal olefin stock	6.9 g NAF base fluid/100 g wet drill cuttings [8.1.1.14]	Daily [8.1.1.15]	Grab
	C_{12}-C_{14} ester or C_8 ester stock	9.4 g NAF base Fluid/100 g wet drill cuttings [8.1.1.14]	Daily [8.1.1.15]	Grab

Table Notes that apply to both Table 30 and Table 31 are provided in the following sections.

8.1.1.1 Report on monthly DMRs estimates of both the maximum daily volumes and the average daily discharge volumes by dividing the monthly total volume discharged by the number of days discharges occurred. Report the total monthly volumes in the End of Well Report (EOW), see Section 11.4.1.

8.1.1.2 Depth-dependent discharge rates are based on MLLW levels at the location of discharge.

8.1.1.3 Per EPA Method 1619 - Drilling Fluids Toxicity Test. See 40 CFR 435, Subpart A, Appendix 2. At the EOW, a sample must be collected for toxicity testing where no mineral oil is used. This sample can also serve as the monthly monitoring sample.

8.1.1.4 The permittee must perform the Static Sheen Test (EPA Method 1617) on separate samples of drilling fluids and drill cuttings, on samples collected each day of discharge and prior to bulk discharges. For discharge below ice or during periods of unstable or broken ice, water temperature for the Static Sheen Test must approximate surface water temperatures at ice breakup. Whenever fluids or cuttings fail the Static Sheen Test, and a discharge has occurred in the past 24 hours, the permittee is required to analyze an undiluted sample of the material which failed the test to determine the presence or absence of diesel oil. The determination and reporting results must be performed according to Section 8.1.1.5.

8.1.1.5 Compliance with the prohibition of diesel oil must be demonstrated by gas chromatography (GC) analysis of drilling fluids collected from the mud used at the greatest well depth ("EOW" sample) and of any drilling fluids or drill cuttings which fail the daily Static Sheen Test per Section 8.1.1.4. In all cases, the determination of the presence or absence of diesel oil must be based on a comparison of the fingerprint of the sample and of the diesel oil in storage at the facility. The method for analysis must be EPA SW846 Method 8015C (2007). Gas chromatography/mass spectrometry (GC/MS) may be used if an instance should arise where the permittee and DEC determine that greater resolution of the drilling fluid "fingerprint" is needed for a particular drilling fluid sample. If the permittee elects to confirm the results of Method 8015C, the GC/MS methods described in EPA 821-R-92-008 may be used. The results and raw data, including the spectra, from the GC analysis must be provided to DEC by written report (1) within 30 days of a positive result with the Static Sheen Test when a discharge has occurred, or (2) for the EOW analysis, within 90 days of well completion, per Section 11.4.1.

8.1.1.6 The permittee must analyze a representative sample of stock barite once prior to drilling each well and submit the results for total mercury and total cadmium on the DMR for the month in which drilling of the well commenced. Analyses must be conducted using EPA Methods 245.5 or 7471b for mercury and 200.7 for cadmium and results expressed as mg/kg (dry weight) of barite. If more than one well is drilled at a site, new analyses are not required for subsequent wells if no new supplies of barite have been received since the previous analysis. In this case, a comment must be included in the DMR stating that no new barite was received since the last reported analysis. A permittee may also provide certification, as documented by the supplier(s), that the barite meets the above limits. The concentration of mercury and cadmium in stock barite must be reported on the DMR as documented by the supplier.

8.1.1.7 At EOW, a sample must be collected for toxicity testing where no mineral oil is used. This sample can also serve as the monthly sample.

Additional table notes that apply only to Class B3 in Table 31 are in the following sections.

8.1.1.8 Applicable stock base fluids include C_{16}-C_{18} internal olefin, C_{12}-C_{14} ester, or C_8 ester.

8.1.1.9 PAH mass ratio = [mass (g) of PAH (as phenanthrene)] ÷ [mass (g) of stock base fluid] as determined by EPA Method 1654, Revision A, entitled “PAH Content of Oil by HPLC/UV,” December 1992. For analysis of TAH and TAqH, all analytical requirements cited in the Alaska Standards, 18 ACC 70.020(b) are applicable.

8.1.1.10 Base fluid sediment toxicity ratio = [10-day LC_{50} of C_{16}-C_{18} internal olefin, C_{12}-C_{14} ester or C_8 ester] ÷ [10-day LC_{50} of stock base fluid] as determined by ASTM E 1367-99 method: “Standard Guide for Conducting 10-day Static Sediment Toxicity Tests with Marine and Estuarine Amphipods,” 1992, after preparing the sediment according to the method specified at 40 CFR 435, Subpart A, Appendix 3. Results of up to 3 tests may be averaged to determine compliance, using 2 samples from the same lot of stock fluids. Equivalent aliquots of one homogenized sample must be split by laboratory (parts 1A and 1B) and tested separately if averaging is used. Permittees may show compliance based on test results from part 1A or from the rounded arithmetic average of the test results from part 1A and 1B. Permittees may also test the second sample for compliance. Where the second sample is analyzed, operators will determine compliance using the arithmetic average of the results from all 3 tests. Permittees shall report the appropriate number on the DMR attach documentation showing how the number was calculated and all applicable test reports.

8.1.1.11 Biodegradation rate ratio = [cumulative gas production (ml) of C_{16}-C_{18} internal olefin, C_{12}-C_{14} ester or C_8 ester] ÷ [cumulative gas production (ml) of stock base fluid], both at 275 days as determined by ISO 11734:1995 method: "Water quality - Evaluation of the 'ultimate' anaerobic biodegradability of organic compounds in digested sludge--Method by measurement of the biogas production (1995 edition)" as modified for the marine environment.

Compliance with the biodegradation limit will be determined using the following ratio:

$$\frac{\text{\% Theoretical Gas Production of Reference Fluid}}{\text{\% Theoretical Gas Production of NAF}} \leq 1.0$$

Where: NAF = stock base fluid being tested for compliance

Results of up to three tests may be averaged to determine compliance, using 2 samples from the same lot of stock fluids. Equivalent aliquots of one homogenized sample must be split by laboratory (parts 1A and 1B) and tested separately if averaging is used. Permittees may show compliance based on test results from part 1A or from the rounded arithmetic average of the test results from part 1A and 1B. Permittees may also test the second sample for compliance. Where the second sample is analyzed, operators will determine compliance using the arithmetic average of the results from all three tests. Permittees shall report the appropriate number on the DMR. With the DMR, the permittee must submit documentation showing how the number was calculated and all applicable test reports.

8.1.1.12 Drilling fluid sediment toxicity ratio = [4-day LC_{50} of C_{16}-C_{18} internal olefin] ÷ [4-day LC_{50} of drilling fluid removed from drill cuttings at the solids control equipment] as determined by American Standard Test Methods (ASTM) E 1367-99 method: "Standard Guide for Conducting Static Sediment Toxicity Tests with Marine and Estuarine Amphipods" (1999), after preparing the sediment according to the method specified in Appendix B of the Permit. Results of up to three tests may be averaged to determine compliance, using two grab samples collected no more than 15 minutes apart. Equivalent aliquots of the first, homogenized sample must be split by the laboratory (parts 1A and 1B) and tested separately if averaging is used. Permittees may show compliance based on test results from part 1A or from the rounded arithmetic average of the test results from parts 1A and 1B. Permittees may also test the second sample for compliance with this limit. Where the second sample is analyzed, operators will determine compliance using the arithmetic average of the results from all three tests. Permittees shall report the appropriate number on the DMR. With the DMR, the permittee must submit documentation showing how the number was calculated and all applicable test reports.

8.1.1.13 Prior to drilling fluids being shipped offshore, no discharge is determined by the GC/MS compliance assurance method (Appendix 5 of 40 CFR, 435, Subpart A), and, prior to discharge by it is determined by the Reverse Phase Extraction (RPE) method (Appendix 6 of 40 CFR 435, Subpart A) applied to drilling fluid removed from drill cuttings.

The GC/MS method reports results for the GC/MS test as percent crude contamination when calibrated for a specific crude oil. In order to define an applicable pass/fail limit to cover a variety of crude oils, the same crude oil used in calibration of the RPE test shall be used to calibrate the GC/MS test results to a standardized ratio of the target aromatic ION Scan 105. Based on the performance of a range of crude oils against standardized ratio, a value will be selected as a pass/fail standard which will represent detection of crude oil.

If the operator wishes to confirm the results of the RPE method, the operator may use the GC/MS compliance assurance method. Results from the GC/MS compliance assurance method shall supersede the results of the RPE method (Appendix 6, 40 CFR 435, Subpart A).

8.1.1.14 The approved test method for permit compliance is identified as: the American Petroleum Institute (API) Retort Test Method described in Appendix 7, 40 CFR 435, Subpart A. The required sampling, handling, and documentation procedures are listed in Addendum A, 40 CFR 435, Subpart A, Appendix 7.

8.1.1.15 Monitoring shall be performed at least once per day when generating new cuttings. Operators conducting fast drilling (i.e., greater than 500 linear feet advancement of the drill bit per day using non-aqueous fluids) shall collect and analyze one set of drill cuttings samples per 500 linear feet drilled, with a maximum of three sets per day. Operators shall collect a single discrete drill cuttings sample for each point of discharge to the ocean. The weighted average of the results of all discharge points for each sampling interval will be used to determine compliance.

Other Requirements for Class B Fluids Not in Table Notes are in the Following Sections

8.1.1.16 Mineral Oil Pills for Class B Fluids

The discharge of residual amounts of mineral oil pills (mineral oil plus additives) is authorized by this general permit provided that the mineral oil pill and at least a 50 barrels (bbl) buffer of drilling fluid on either side of the pill are removed from the circulating drilling fluid system and not discharged to waters of the US. If more than one pill is applied to a single well, the previous pill and buffer must be removed prior to application of a subsequent pill.

Residual mineral oil concentration in the discharged fluid must not exceed 2 % volume/volume as determined by Appendix 7 to Subpart A of 40 CFR 435 (Derived from American Petroleum Institute (API) Recommended Practice 13B-2)(EPA Method 1674). The permittee must report the following information within 60 days of the discharge if drilling fluid containing residual mineral oil pill (after pill and buffer removal) is discharged:

a) Dates of pill application, recovery, and discharge;
b) Results of the Drilling Fluids Toxicity Test on samples of the mud before each pill is added and after removal of each pill and buffer (taken when residual mineral oil pill concentration is expected to be greatest);
c) Name of spotting compound and mineral oil product used;
d) Volumes of spotting compound, mineral oil, water, and barite in the pill;
e) Total volume of fluid circulating prior to pill application, volume of pill formulated, and volume of pill circulated;
f) Volume of pill recovered, volume of mud buffer recovered, and volume of fluid circulating after pill and buffer recovery;
g) Percent recovery of the pill (include calculations);
h) Estimated concentrations of residual spotting compound and mineral oil in the sample of mud discharged, as determined from amounts added and total mud volume circulating prior to pill application;
i) Measured oil content of the mud samples, as determined by the API retort method; and
j) An itemization of other drilling fluid components and specialty additives contained in the discharged fluid concentrations reported in gallons per bbl (gal/bbl) or pounds per bbl (lbs/bbl).

8.1.1.17 The permittee is limited to drilling discharges from no more than five oil and gas exploration

wells (Class B Fluids) at a single exploration site unless written approval is provided by DEC on a case-by-case basis. The permittee must submit the following information to DEC in writing for consideration for approval of the discharge from additional wells:

a) Number of additional wells;

b) Technical analysis of additional impacts to the receiving waters;

c) Drilling fluid category and group for each well; and

d) Well information for each additional well, including well name, number latitude, longitude, beginning drill date, and hole diameter.

8.1.2 Effluent Limitations and Monitoring Requirements for Class C Drilling Fluids and Drill Cuttings (Discharge 001).

Class C drilling fluids are applicable to geotechnical surveys or HDD projects that use drilling fluids and discharge to Cook Inlet. The effluent limitations and monitoring requirements are summarized in Table 32.

Table 32: Effluent Limitations and Monitoring Requirements for Class C1-C3 Drilling Fluids (Discharge 001)

Pollutant Parameter	Effluent Limitations	Monitoring Requirements	
		Frequency	Sample Type
Volume Million Gallons (MG) [8.1.2.1]	Report	Monthly	Estimate
Oil and Grease (Sheen) [8.1.2.1 , 8.1.2.1]	No discharge	Daily	Visual
Mercury [8.1.2.3]	1 mg per kilogram (mg/kg)	Once per well	Grab
Cadmium [8.1.2.3]	3 mg/kg	Once per well	Grab

8.1.2.1 Fluid Volume, Visual Sheen, and Inadvertent Releases. The permittee must maintain a daily log while conducting drilling using Class C1, C2, or C3 drilling fluids (e.g., for HDD and geotechnical projects) to record daily visual observations (i.e., observation for visual sheen) and estimated discharge volumes. The daily log must be maintained onsite and made available to DEC upon request. For HDD projects, visual observations must be made at low tide conditions when the borehole advances beyond the shoreline to observe for inadvertent releases of drilling fluids. The permittee must notify DEC as soon as possible upon observation of an inadvertent release and implement procedures included in the DFP to stop the release (See Section 11.6.3.3).

Report on DMRs estimates of the maximum daily volumes and the average daily discharge volumes by dividing the monthly total volume discharged by the number of days discharges occurred. Report the total monthly volumes and estimates of lost fluids in the End of Project (EOP) Report, (See Section 11.4.1).

8.1.2.2 Observation of Receiving Water for Sheen. The permittee must monitor for sheen by observing the surface of the receiving water in the vicinity of the discharge during daylight hours at low and high slack tides. Observations must be made while drilling and after discharge and recorded in a daily operating log. The daily log must be maintained on site and made available to DEC upon request. Visual sheen tests must also be recorded and submitted in the EOP Report (See Section 11.4.1).

8.1.2.3 Mercury and Cadmium. For Class C3 Fluids, the permittee must analyze a representative sample of stock barite once prior to initiating the drilling program and submit the results for total mercury and total cadmium on the DMR for the month in which drilling commenced. Analyses must be conducted using EPA Methods 245.5 or 7471b for mercury and 200.7 for cadmium and results expressed as mg/kg (dry weight) of barite. If more than one well is drilled at a site, new analyses are not required for subsequent wells if no new supplies of barite have been received since the previous analysis. In this case, a comment must be included in the DMR stating that no new barite was received since the last reported analysis. A permittee may also provide certification, as documented by the supplier(s), that the barite meets the above limits. The concentration of mercury and cadmium in stock barite must be reported on the DMR as documented by the supplier.

The following Additional Monitoring Requirements May Apply to Various Drilling Fluid Classes

8.1.3 Chemical Inventory: For all drilling fluid systems discharged, the permittee must maintain a precise chemical inventory of all constituents added downhole, including all drilling fluid additives used to meet specific drilling requirements. This information is reported as part of the EOW or EOP report described in Section 11.4.1.

8.1.4 Metals Analysis: For all drilling fluid systems using barite (Class B2 and B3 and Class C3), the permittee must analyze each discharged fluid system for the following metals: barium, cadmium, chromium, copper, mercury, zinc, and lead. Analyses for total recoverable concentrations must be conducted and reported for each metal utilizing the methods specified in 40 CFR Part 136. The results must be reported in "mg/kg of whole mud (dry weight)" and the moisture content (percent by weight) of the original drilling fluid sample. Samples must be collected when the residual mineral oil concentration is at its maximum value. If no mineral oil is used, the analysis must be done on a drilling fluid sample from the mud system used at the greatest well depth, or well length (i.e., just prior to daylighting for HDD). For Class C3 drilling fluids, a single sample from that represents the deepest borehole in the project is sampled. All samples must be collected prior to any pre-dilution. The metal analysis must be submitted in the EOW or EOP Report per Section 11.4.1.

8.2 Requirements for Deck Drainage (Discharge 002)

The Permittee must limit and monitor deck drainage discharges per Table 33.

Table 33: Effluent Limits and Monitoring Requirements for Deck Drainage (Discharge 002)

Parameter (Units)	Effluent Limitations	Monitoring Requirements	
		Frequency	Type
Total Flow Volume (mgd) [8.2.1]	Report	Monthly	Estimated
Oil and Grease (Sheen) 8.1.2.2	No Discharge	Daily	Visual

8.2.1 Total Flow Volume

The Permit requires flow to be estimated in daily, maintained in a log at the facility, and made available to DEC upon request. The total monthly volume must be reported on the DMR.

8.2.2 Oil and Grease (Sheen)

The permittee must ensure that deck drainage contaminated with oil and grease is processed through an oil-water separator, or other oil removal process, prior to discharge. Once per discharge event, the permittee must observe the receiving water surface during a time when observation of the water surface is possible and record observations in a daily log maintained onsite. If conditions prevent observations, the permittee may use the Static Sheet Test

(EPA Method 1617). Static Sheen Test equipment must be maintained onsite.

8.2.3 Drain Separation BMPs

Per Section 11.3.1.1, the permittee must separate area drains for wash-down and rainfall that may be contaminated with oil and grease from those area drains that would not be contaminated so that the waste streams are not comingled. Deck drainage that is contaminated with oil and grease must be processed through an oil-water separator, or other similar treatment process, prior to discharge.

8.3 Requirements for Domestic Wastewater (Discharge 003)

The permitting of domestic wastewater in the Permit requires an understanding of certain terminology associated with implementation of Effluent Limitation Guidelines for Oil and Gas Production. For terminology definitions see Section 4.3 or Appendix C. The permittee must comply with the effluent limitations and monitoring requirements in Table 34.

Table 34: Effluent Limitations and Monitoring Requirements for Domestic Wastewater (Discharge 003)

Discharge Category	Effluent Parameter (Units)	Effluent Limitations		Monitoring Requirements	
		MDL	AML	Frequency	Sample Type
All Domestic Wastewater, Discharges [8.3.2]	Flow Volume (mgd) [8.3.1]	Report	Report	1/Month	Estimate
	TRC (mg/L)	1.0 mg/L Minimum [8.3.3]	-	1/Month	Grab
	TRC (mg/L)	1.0 mg/L [8.3.4]	-	1/Month	Grab
	Floating Solids [8.3.5]	No Discharge		1/Day	Observation
M10 MSD and MSD/BTUs	BOD_5 (mg/L)	60 mg/l	30 mg/l	1/Month	Grab
	TSS (mg/L)	67 mg/l	51 mg/l	1/Month	Grab
M9IM MSD and MSD/BTUs	BOD_5 (mg/L)	60 mg/l	30 mg/l	1/Month	Grab
	TSS (mg/L)	67 mg/l	51 mg/l	1/Month	Grab
M10 BTUs	BOD_5 (mg/L)	60 mg/l	30 mg/l	1/Month	Grab
	TSS [8.3.6] (mg/L)	60 mg/l	30 mg/l	1/Month	Grab
M9IM BTUs	BOD_5 (mg/L)	90 mg/l	48 mg/l	1/Month	Grab
	TSS [0] (mg/L)	108 mg/l	56 mg/l	1/Month	Grab
Note: Table notes refer to permit sections below this Table.					

8.3.1 Total Flow Volume.

The Permit requires effluent flow volume to be to measured or estimated for each month a discharge occurs with the average monthly and maximum daily flow reported on the DMR.

8.3.2 Comingled Graywater and Blackwater.

In cases where treated domestic wastewater (black water) and graywater are commingled prior to discharge, the combined discharge is considered domestic wastewater per 18 AAC 72 and the limitations in Table 34 apply to the commingled discharge. See Section 11.7 for additional reporting requirements for domestic wastewater and graywater.

8.3.3 Total Residual Chlorine Minimum (Post-Chlorination before Dechlorination).

The 1.0 mg/L minimum TRC concentration is a surrogate parameter for fecal coliform and enterococci. Maintain as close to the minimum limit concentration of 1.0 mg/L as practicable

and measure immediately after chlorination.

8.3.4 Total Residual Chlorine Maximum (Post-Dechlorination).

The 1.0 mg/L maximum daily limit is measured immediately prior to discharge after a required dechlorination step.

8.3.5 Floating Solids, Foam, and Garbage.

The permittee must monitor by observing the surface of the receiving water in the vicinity of the outfall(s) during daylight at the time of maximum estimated discharge and during conditions when observation on the surface of the receiving water is possible in the vicinity of the discharge. For domestic wastewater, observations must follow either the morning or midday meal. Observations must be recorded in daily operating logs kept onsite and made available upon request by DEC.

8.3.6 TSS Limit for BTUs.

Compliance with the TSS limit for BTUs can be net value for those facilities that use filtered seawater for flushing and treat with BTUs. The TSS of the effluent may be reported as the net value by subtracting the TSS value of the intake water from the TSS value of the effluent. Report the TSS value of the intake water in the comment section of the DMR. Samples collected to determine the TSS value of the intake water must be taken on the same day, and during the same time period that the effluent sample is taken. Intake water samples must be taken at the point where the water enters the facility prior to mixing with other flows. Influent samples must be taken at the same frequency that effluent samples are taken.

8.4 Requirements for Graywater (Discharge 004)

Graywater is considered domestic wastewater and must meet the requirements in the most current version of 18 AAC 72 to be discharged separately from domestic wastewater under Discharge 004 of the Permit. The permittee must limit and monitor graywater discharges per Table 35.

Table 35: Effluent Limits and Monitoring Requirements for Graywater (004)

Parameter (Unit)	Effluent Limitations	Monitoring Requirements	
		Frequency	Sample Type
Flow Volume (mgd) [8.4.1]	Report	Monthly	Estimate or Measured
Floating solids, foam, garbage [8.4.2]	No Discharge	Daily	Observation
Oil and grease (sheen) [8.4.3]	No Discharge	Daily	Observation
Total Residual Chlorine (mg/L) [8.4.4]	Maximum 1.0	Monthly	Grab

8.4.1 Total Flow Volume.

The Permit requires effluent flow volume to be to measured or estimated for each month a discharge occurs with the average monthly flow reported on the DMR.

8.4.2 Floating Solids, Foam, and Garbage.

The Permit prohibits the discharge of floating solids, foam, and garbage as determined by a visual observation of the receiving water surface at a minimum frequency of once per day during daylight at the time of maximum estimated discharge (e.g., following morning or midday meals). Monitoring of the observations must be recorded in a daily operating log and made available to DEC upon request.

8.4.3 Oil and Grease (Visible Sheen).

The Permit prohibits the discharge of oil and grease as determined by a visible sheen on the

receiving water surface per 18 AAC 70.020(17). Receiving water observations must be conducted once per day during daylight at the time of maximum estimated discharge (e.g., following morning or midday meals). Observations must be recorded in a daily operating log and made available to DEC upon request.

8.4.4 Total Residual Chlorine Maximum.

For MODUs that use an MSD to treat graywater to greater than primary treatment, the Permit establishes a maximum limit on the concentration of TRC of 1.0 mg/L after dechlorination and prior to discharge. If the MODU uses a treatment system other than an MSD to meet the primary treatment requirement, the 1 mg/l maximum TRC limit does not apply.

8.4.5 Discharge-Specific BMPs.

To support the narrative limits for floating solids, foam, garbage, and oil and grease the permittee must develop specific housekeeping BMPs to minimize introduction of deleterious substances at the source. For graywater discharges treated with MSDs, the permittee must also develop specific BMPs to ensure proper operation and maintenance of the dechlorination system (See Section 11.3.1.2).

8.5 Requirements for Miscellaneous Discharges (Discharges 005-014)

Miscellaneous discharges include desalination unit wastes (Discharge 005); blowout preventer fluid (Discharge 006); boiler blowdown (Discharge 007): fire control system test water (Discharge 008); non-contact cooling water (Discharge 009); uncontaminated ballast water (Discharge 010); bilge water (Discharge 011); excess cement slurry (Discharge 012); mud, cuttings, and cement at the seafloor (Discharge 013); and waterflooding (Discharge 014). The permittee must comply with the effluent limitations and monitoring requirements in Table 36.

Table 36: Effluent Limitations and Monitoring Requirements for Miscellaneous (Discharges 005-014)

Parameter (Units)	Effluent Limitations	Monitoring Requirements	
		Frequency	Sample Type
Maximum Daily Volume (mgd) [8.5.1]	Report	Monthly	Estimate
Oil and Grease (Sheen) [8.5.2]	No Discharge	Once/Week	Visual
Chemical Additives [8.5.3]	Report	Once/Year	Calculate
Chronic WET (TU_c) [8.5.4, 8.5.5 and 8.9]	Report	Varies	Grab or [8.5.5.5] Composite

8.5.1 Maximum Daily Flow

The Permit requires the permittee to record estimated or measured daily flow volumes consistently in a daily log maintained onsite and report the maximum daily volume during a given month in mgd on the DMR. If chemicals have been added, the permittee must conduct a chemical inventory per Section 8.5.3 and if any 24-hour flow volume is greater than 0.010 mgd (10,000 gallons per day), the discharge qualifies for chronic WET testing per Section 8.8 and permittee must collect one grab sample that is representative of the chemically treated effluent to characterize the discharge.

8.5.2 Oil and Grease (Visible Sheen)

The prohibition of free oil applies to the miscellaneous discharges blowout preventer fluid (Discharge 006), uncontaminated ballast water (Discharge 010), bilge water (Discharge 011), excess cement slurry (Discharge 012), and mud, cuttings, cement at the seafloor (Discharge 013). Compliance is based on observation of a visible sheen on the water surface during slack tide while discharging or by Static Sheen Test at the permittees option. Static Sheen Test equipment must be maintained at the facility. The permittee must ensure that contaminated

ballast water (Discharge 010) or bilge water (Discharge 011) must be processed through an oil-water separator, or similar process to remove oil and grease, prior to discharge. For discharges of blowout preventer test fluid (Discharge 006), uncontaminated ballast water (Discharge 010), excess cement slurry (Discharge 012), and drilling fluids, drill cuttings and cement at the seafloor (Discharge 013) the permittee must develop specific BMPs to support the no discharge of free oil limitation (See Section 11.3.1.3).

8.5.3 Chemical Use Optimization and Inventory

The permittee is allowed to use chemical additives in miscellaneous discharges but in a manner that does not exceed the most stringent of the following four constraints:

a) The maximum concentrations and any other conditions specified in the EPA product registration labeling if the chemical is an EPA registered chemical;

b) The maximum manufacturer's recommended concentration;

c) 500 mg/L; or

d) The estimated chronic toxicity based on the mixed concentration of the chemical(s) in the waste stream should not be greater than Pollution Reduction Action Level for the facility. The chronic toxicity estimate can be based on the most limiting 25 % effect concentration (EC_{25}) listed from the aquatic toxicological information obtained in the SDS for the chemical, if available. Note that when only acute toxicity data is provided on an SDS, the permittee must use a reported acute to chronic ratio (ACR) for that chemical and species, or a default ACR of 10, to estimate the TU_c of the mixture.

Per this Section, the permittee must also maintain a precise chemical inventory of all constituents added to these discharges, including the time, dose, and frequency of each chemical additive used in miscellaneous discharges. The permittee must submit these inventory records to DEC annually by January 31 of each year.

8.5.4 Specific Pollution Reduction BMPs and BMP Revision Action Levels

For the miscellaneous discharges desalination unit waste (Discharge 005), noncontact cooling water (Discharge 009), and waterflooding (Discharge 014) the permittee must develop and implement a chemical dosing BMP to optimize the use of chemicals and to minimize the potential for chronic toxicity in miscellaneous discharges per Section 11.3.1.4. This requirement applies to any individual, or commingled, discharges of desalination waste, noncontact cooling water and waterflooding that have chemical additives and discharge greater than 10,000 gallons per day. In addition, the permittee must make revisions to existing BMPs should any single chronic WET result exceed the PR BMP Revision Action Levels specified in Table 37 and Table 38.

Table 37: Action Levels for Unspecified Surface (Discharges005, 009, and 014)

Permitted Discharge Rate (mgd)	Action Level (TU_c)
0.01 ≤ 0.02	531
0.02 ≤ 0.05	448
0.05 ≤ 0.1	358
0.1 ≤ 0.5	303
0.5 ≤ 1.0	204
1.0 ≤ 2.5	173
2.5 ≤ 5.0	138
> 5.0	116

Table 38: PR Action Levels for Unspecified Submerged (Discharges 005, 009, and 014)

Permitted Discharge Rate (mgd)	Action Level (TU_c)
0.01 ≤ 0.02	329
0.02 ≤ 0.05	263
0.05 ≤ 0.1	195
0.1 ≤ 0.5	156
0.5 ≤ 1.0	92
1.0 ≤ 2.5	74
2.5 ≤ 5.0	55
> 5.0	44

Existing facilities covered by the Permit will have PR BMP Action Levels as shown in Table 39. For any new platforms or MODUs that do not have a PR BMP Revision Action Level specified in Table 39, the appropriate PR BMP Revision Action Level per Table 37 or Table 38 will be based on the maximum flow rate among the miscellaneous discharges included in the NOI and issued in the authorization letter prior to discharge.

Table 39: PR Action Levels for Specified Platforms or MODUs (Discharges 005, 009, and 014)

Platform or MODU	Discharge Type	Action Level (TU_c)
Granite Point	Surface	152
King Salmon	Surface	128
Monopod	Surface	129
Grayling	Surface	116
Dolly Varden	Surface	115
Osprey	Submerged	127
Randolph Yost	Surface	173
Spartan 151	Surface	189
Steelhead	Submerged	73
MGS-C	Submerged	136

If a PR BMP Revision Action Level is exceeded, the permittee must revise the BMP to achieve less toxicity in the subsequent test. These BMPs could be operational or physical modifications to the chemical dosing system. Exceeding a PR BMP Revision Action Level also triggers a requirement for the permittee to evaluate the system and initiate an update to line drawings as part of the BMP Plan revision. Regardless of exceeding a PR BMP Revision Action Level, the permittees will be required to submit updated line drawings of the discharge piping systems for each authorized discharge where chemicals are used and discharge greater than 10,000 gpd with the next application for reissuance. The updated line drawings will also be used to

evaluate the written requests for reducing WET monitoring frequency. If the discharge of chemicals is eliminated, chronic WET testing is not required and line drawings will not be required in the application.

The permittee must notify DEC in writing within one week of exceeding a chronic WET PR BMP Revision Action Level and submit a letter within 60 days specifying what BMP revisions will be implemented prior to the next scheduled chronic WET monitoring event. If BMPs require modification to the physical system, updated line diagrams must be developed and submitted to DEC as an attachment to the letter. The revised BMP must be implemented to satisfy compliance with this specific BMP requirement for pollution reduction. Revisions must continue until the PR BMP Plan Action Level is achieved.

As an incentive to PR, if the permittee demonstrates that sampling procedures were adequate to collect a representative sample and toxicity does not exceed PR BMP Revision Action Levels in two consecutive WET monitoring events, they can submit a written request for monitoring frequency reduction for Department approval. Written requests must include updated line diagrams, a narrative of sample collection procedures used ensure representative sampling (See Section 11.2), and cover letter describing the pollution reduction methods used to reduce chronic toxicity. Only one step reduction may be granted by DEC during the term of the Permit.

8.5.5 Unique WET Testing Requirements for Miscellaneous Discharges

Chronic WET monitoring applies to Desalination Units (005), Blowout Preventer Fluid (006), Boiler Blowdown (007), Fire Control System Test Water (008), Non-contact Cooling Water (009), Uncontaminated Ballast Water (010), and Bilge Water (011) if chemical additives are used and greater than 0.010 mgd (10,000 gpd) is discharged over a 24-hour period, including discharges that may be commingled and discharged accumulatively. This Requirement does not apply to Excess Cement Slurry ((012) or Muds, Cuttings, and Cement at the Seafloor (013) regardless of chemical use of volumes discharged.

8.5.5.1 Test Species: For miscellaneous discharges that have chemical additives and discharge 0.01 mgd (10,000 gpd) or more in a 24-hour period, the permittee is required to conduct chronic WET monitoring on one invertebrate species on frequency established in Section 8.9.1.2.

8.5.5.2 Monitoring Frequency: When WET monitoring is triggered based on the condition of chemical use and 24-hour flow, the following frequencies must be adhered to:

8.5.5.3 For MODUs, the frequency is annual when discharges occur.

8.5.5.4 For fixed platforms, the monitoring frequency is semi-annual with a minimum of 120 days between any two sample events. After two consecutive chronic WET results that are below the PR BMP Revision Action Levels (See Section 8.5.4), the permittee may submit a written request to reduce the frequency to annual. Approval is also contingent upon collection of representative samples of the effluent and submittal per Section 8.5.5.5)

8.5.5.5 Sample Collection: The permittee must evaluate chemical dosing practices versus sample collection methods and timing in order to ensure the collected sample is representative of the toxicity of the dosing. For example, for continuous discharges with continuous chemical injection rates a grab or composite sample could result in collection of a representative sample. However, if the discharge is intermittent and/or chemical dosing is discontinuous, the permittee must evaluate the occurrence of spiked concentrations in the effluent to properly time sample events to ensure a representative sample is collected. Each facility must have a Quality Assurance Project Plan (QAPP) that specifies this procedure (See Section 11.2). Requests for chronic WET monitoring frequency reductions must include submittal requirements in Section 8.5.4 and this procedure and a narrative addressing representativeness

of the sampling events.

8.6 Requirements for Produced Water (Discharge 015)

The permittee must comply with the general effluent limitations for produced water and the facility-specific effluent limits and monitoring requirements noted in Table 40 through Table 47. The discharge of produced water from exploration MODUs is not authorized by the Permit.

8.6.1 Rerouting Platform Produced Water to Onshore Treatment Facilities.

In situations where fixed platforms are not able to treat produced water and discharge at the facility, the permittee may route their produced water discharge to onshore facilities for treatment and discharge. In addition to submitting a DMR with the "no discharge" box marked, the permittee must indicate in the comment section that produced water was rerouted to a specific onshore treatment facility.

8.6.2 Trading Bay Production Facility Groundwater.

Trading Bay is authorized to discharge treated ground water extracted pursuant to State Compliance Order #91-2301-053-02 as part of the produced water waste stream. The produced water limitations and monitoring requirements apply to the combined waste stream of treated ground water and produced water.

8.6.3 Commingling Waste Streams.

The permittee is allowed to commingle certain waste streams for the purpose of treating and disposing in compliance with the limitations in this Section. These waste streams include, deck drainage (Discharge 002), completion fluids (Discharge 016), workover fluids (Discharge 017), well treatment fluids (Discharge 018), test fluids (Discharge 019), contaminated hydrostatic test water (Discharge 020), and incidental spills or excavation dewatering in, or near to, contaminated sites.

8.6.4 Spill Clean-Up.

Water that is collected as a result of spill clean-up can be treated as produced water and discharged with the produced water waste stream. The permittee must include their intent, referencing the Permit section, in the spill report submitted to DEC Division of Spill Prevention and Response.

8.6.5 Contaminated Excavation Dewatering

Water contaminated with hydrocarbons that is collected as a result dewatering excavations to install or repair ancillary underground infrastructure can be treated as produced water and discharged with the produced water waste stream. The permittee must contact the DEC Contaminated Sites Program to verify site contamination is consistent with characteristics of produced water (e.g., petroleum hydrocarbon contaminants). The permittee must also submit a written request to the Oil and Gas Section in the DEC Wastewater Discharge Authorization Program to obtain written approval on a case-by-case basis.

8.6.6 Commingling for Line Freeze Protection

If excess waterflood water is added to the produced water discharge in order to minimize the possibility of line freezing, then the discharge must be considered produced water for monitoring purposes. The estimated waterflood flow rate must be reported in the comment section of the DMR.

8.6.7 Facility-Specific Effluent Limitations and Monitoring Requirements.

Facility-specific effluent limits and monitoring requirements for Flow, pH, Oil and Grease, TAH, TAqH, Total Recoverable Copper, Total Recoverable Manganese, Total Recoverable Silver, Total Recoverable Zinc, Total Mercury, and Chronic WET are provided in Table 40 through Table 47. For table notes, refer to sections following Table 47.

Table 40: Trading Bay Production Facility Effluent Limitations and Monitoring Requirements for Produced Water Discharges

Parameter (Units)	Effluent Limitations		Monitoring Requirements	
	MDL	AML	Frequency	Sample Type
Flow Rate (mgd)	Report	8.4	1/Week	Estimate
pH (Standard Units (SU)) [8.6.7.1]	6.0 < pH < 9.0		1/Week	Grab
Oil and Grease (mg/L)	42 mg/l	29 mg/l	1/Week	Grab
TAH (mg/L)	17	12	1/Month	Grab
Copper (µg/L)	22	12	1/Quarter	Grab
TAqH (mg/L)	Report		1/Quarter	Grab
Silver (µg/L)	47	23	1/Quarter	Grab
Zinc (mg/L)	1.9	0.9	1/Quarter	Grab
Mercury (µg/L)	1.0	0.6	1/Quarter	Grab
Manganese (mg/L)	50	25	1/Quarter	Grab
WET (TU_c) [8.6.7.2, 8.6.7.3 and 8.9]	Report		1/Quarter	Grab or Composite

Table 41: MGS Onshore Effluent Limitations and Monitoring Requirements for Produced Water Discharges

Parameter	Effluent Limitations		Monitoring Requirements	
	MDL	AML	Frequency	Sample Type
Flow Rate (mgd)	Report	0.365	1/Week	Estimate
pH (SU) [8.6.7.1]	6.0 < pH < 9.0		1/Week	Grab
Oil and Grease (mg/L)	42	29	1/Week	Grab
TAH (mg/L)	28	20	1/Month	Grab
Silver (µg/L)	48	19	1/Quarter	Grab
TAqH (mg/L)	Report		1/Quarter	Grab
Copper (µg/L)	79	53	1/Quarter	Grab
Zinc (mg/L)	57	22	1/Quarter	Grab
Mercury (µg/L)	9.5	3.8	1/Quarter	Grab
Manganese (mg/L)	14.8	7.4	1/Quarter	Grab
WET (TU_c) [8.6.7.2, 8.6.7.3 and 8.9]	Report		1/Quarter	Grab or Composite

Table 42: Granite Point Tank Farm Effluent Limitations and Monitoring Requirements for Produced Water Discharges

Parameter	Effluent Limitations		Monitoring Requirements	
	MDL	AML	Frequency	Sample Type
Flow Rate (mgd)	Report	0.195	1/Week	Estimate
pH (SU) [8.6.7.1]	6.0 < pH < 9.0		1/Week	Grab
Oil and Grease (mg/L)	42	29	1/Week	Grab
TAH (mg/L)	20	14	1/Month	Grab
Copper (µg/L)	54	21	1/Quarter	Grab
TAqH (mg/L)	Report		1/Quarter	Grab
Silver (µg/L)	74	37	2/Year	Grab
Zinc (mg/L)	3.1	1.5	2/Year	Grab
Mercury (µg/L)	7.9	3.1	2/Year	Grab
Manganese (mg/L)	12.3	6.1	2/Year	Grab
WET (TU_c) [8.6.7.2, 8.6.7.3 and 8.9]	Report		2/Year	Grab or Composite

Table 43: Baker Platform Effluent Limitations and Monitoring Requirements for Produced Water Discharges

Parameter	Effluent Limitations		Monitoring Requirements	
	MDL	AML	Frequency	Sample Type
Flow Rate (mgd)	Report	0.045	1/Week	Estimate
pH (SU)	6.0 < pH < 9.0		1/Week	Grab
Oil and Grease (Sheen) [8.6.7.1]	Report		1/Week	Visual
Oil and Grease (mg/L)	42	29	1/Week	Grab
TAH (mg/L)	47	34	1/Month	Grab
Zinc (mg/L)	13	6	1/Quarter	Grab
TAqH (mg/L)	Report		1/Quarter	Grab
Copper (µg/L)	873	435	2/Year	Grab
Silver (µg/L)	347	173	2/Year	Grab
Mercury (µg/L)	0.4	0.3	2/Year	Grab
Manganese (mg/L)	14.2	7.1	2/Year	Grab
WET (TU_c) [8.6.7.2, 8.6.7.3 and 8.9]	Report		2/Year	Grab or Composite

Table 44: Bruce Platform Effluent Limitations and Monitoring Requirements for Produced Water Discharges

Parameter	Effluent Limitations		Monitoring Requirements	
	MDL	AML	Frequency	Sample Type
Flow Rate (mgd)	Report	0.025	1/Week	Estimate
pH (SU) [8.6.7.1]	6.0 < pH < 9.0		1/Week	Grab
Oil and Grease (Sheen) [8.6.7.1]	Report		1/Week	Visual
Oil and Grease (mg/L)	42	29	1/Week	Grab
TAH (mg/L)	46	31	1/Month	Grab
Zinc (mg/L)	25	10	1/Quarter	Grab
TAqH (mg/L)	Report		1/Quarter	Grab
Copper (µg/L)	2,867	1,429	2/Year	Grab
Silver (µg/L)	11.0	7.3	2/Year	Grab
Mercury (µg/L)	9.2	3.7	2/Year	Grab
Manganese (mg/L)	14.4	7.2	2/Year	Grab
WET (TU_c) [8.6.7.2, 8.6.7.3 and 8.9]	Report		2/Year	Grab or Composite

Table 45: Dillon Platform Effluent Limitations and Monitoring Requirements for Produced Water Discharges

Parameter	Effluent Limitations		Monitoring Requirements	
	MDL	**AML**	**Frequency**	**Sample Type**
Flow Rate (mgd)	Report	0.195	1/Week	Estimate
pH (SU)	6.0 < pH < 9.0		1/Week	Grab
Oil and Grease (Sheen) [8.6.7.1]	Report		1/Week	Visual
Oil and Grease (mg/L)	42	29	1/Week	Grab
TAH (mg/L)	42	31	1/Month	Grab
Silver (µg/L)	48	19	1/Quarter	Grab
TAqH (mg/L)	Report		1/Quarter	Grab
Copper (µg/L)	14	9.3	2/Year	Grab
Zinc (mg/L)	2.3	1.2	2/Year	Grab
Mercury (µg/L)	2.5	1.2	2/Year	Grab
Manganese (mg/L)	4.6	2.3	2/Year	Grab
WET (TU_c) [8.6.7.2, 8.6.7.3 and 8.9]	Report		2/Year	Grab or Composite

Table 46: Tyonek A Platform Effluent Limitations and Monitoring Requirements for Produced Water Discharges

Parameter	**Effluent Limitations**		**Monitoring Requirements**	
	MDL	**AML**	**Frequency**	**Sample Type**
Flow Rate (mgd)	Report	0.038	1/Week	Estimate
pH (SU)	6.0 < pH < 9.0		1/Week	Grab
Oil and Grease (Sheen) [8.6.7.1]	Report		1/Week	Visual
Oil and Grease (mg/L)	42	29	1/Week	Grab
TAH (mg/L)	0.14	0.09	1/Month	Grab
Copper (µg/L)	790	247	1/Quarter	Grab
TAqH (mg/L)	Report		1/Quarter	Grab
Silver (µg/L)	411	205	2/Year	Grab
Zinc (mg/L)	17.0	8.4	2/Year	Grab
Mercury (µg/L)	0.10	0.05	2/Year	Grab
Manganese (mg/L)	0.2	0.1	2/Year	Grab
WET (TU_c) [8.6.7.2, 8.6.7.3 and 8.9]	Report		2/Year	Grab or Composite

Table 47: Osprey Platform Effluent Limitations and Monitoring Requirements for Produced Water Discharges

Parameter	Effluent Limitations		Monitoring Requirements	
	MDL	AML	Frequency	Sample Type
Flow Rate (mgd)	Report	1.05	1/Week	Estimate
pH (SU)	6.0 < pH < 9.0		1/Week	Grab
Oil and Grease (Sheen) [8.6.7.1]	Report		1/Week	Visual
Oil and Grease (mg/L)	29	42	1/Week	Grab
TAH (mg/L)	9.0	7.7	1/Week	Grab
Copper (µg/L)	195	97	1/Week	Grab
TAqH (mg/L)	Report		1/Week	
Silver (µg/L)	Report		1/Quarter	Grab
Zinc (µg/L)	Report		1/Quarter	Grab
Mercury (µg/L)	Report		1/Quarter	Grab
Manganese (mg/L)	Report		1/Quarter	Grab
WET (TU_c) [8.6.7.2, 8.6.7.3 and 8.9]	Report		1/Quarter	Grab or Composite

8.6.7.1 Visual Sheen and Supplemental Oil and Grease Monitoring

While discharging from platforms, the permittee shall monitor for oil and grease using visual observations of the receiving water surface in the vicinity of the discharge during periods of the day when observation of a sheen on the water surface is possible. This requirement does not apply to shore based facilities (i.e., TBPF, MGS Onshore, and GPTF) or unmanned platforms. Upon observation of a sheen, a supplemental oil and grease sample must be collected and analyzed.

8.6.7.2 Metal and Chronic WET Monitoring Coordination and Frequency Reductions

Chronic WET monitoring and monitoring for metals must be conducted simultaneously for the minimum frequencies shown. The minimum required frequency for the specified metal and chronic WET can be reduced after demonstration of compliance with the metal limits after four consecutive sample events and the chronic WET results are below the notification levels in Table 48.

Table 48: Produced Water Chronic WET Notification Levels

Facility	Chronic WET Notification Level
TBPF	512
MGS Onshore	334
GPTF	279
Baker Platform	155
Bruce Platform	224
Dillon Platform	243

When both the chronic WET results are below notification levels and metals results have complied with limits in four consecutive monitoring events, the permittee may submit a written request to reduce minimum sampling frequency. Upon receiving DEC approval, the minimum frequency can be reduced from quarterly to twice per year and the minimum frequency of twice per year can be reduced to once per year. Only one reduction can be approved during the permit term. The Osprey Platform must monitor metals and chronic WET quarterly during the full first term of coverage under the Permit.

8.6.7.3 Unique Chronic WET Monitoring Requirements for Produced Water

Per the frequency specified in each facility-specific limits and monitoring table, the permittee is required to conduct chronic WET monitoring for both a vertebrate and invertebrate species discussed in Sections 8.9.1.1 and 8.9.1.2, respectively. The metals required to be monitored are the same frequency as chronic WET and must be analyzed concurrently. Should any chronic WET result exceed the Notification Levels in Table 48 the permittee must research the anomalously high toxicity event and provide written notification to DEC within one week and provide information on any unusual circumstances and assessment as to what may have caused exceeding the notification level. The permittee must repeat the chronic WET and metals monitoring within 30-days of notifying DEC and submit a follow up written notification of the subsequent results. Based on these results, DEC may require additional monitoring per Section 8.12.

8.7 Requirements for Well Treatment (Discharge 016), Completion (Discharge 017), Workover (Discharge 018), and Test Fluids (Discharge 019)

The discharge of well completion fluids, workover fluids, treatment fluids, and test fluids must meet an MDL and AML for oil and grease, pH limits, and narrative limitations. Well completion, workover, treatment and test fluids can be treated and discharged with produced water. Otherwise, the permittee must limit and monitor discharges of well completion fluids (Discharge 016), workover fluids (Discharge 017), treatment fluids (Discharge 018), and test fluids (Discharge 019) per Table 49.

Table 49: Effluent Limits and Monitoring Requirements for Well Completion, Workover, Treatment, and Test Fluids (Discharges 016, 017, 018, and 019)

Parameter (Units)	Effluent Limitations		Monitoring Requirements	
	MDL	AML	Frequency	Sample Type
Discharge Frequency [8.7.1]	Report		Once/Well/Fluid	Occurrences
Maximum Daily Volume (mgd) [8.7.2]	Report		Once/Day	Estimate
Oil and Grease (mg/L) [8.7.3]	42	29	Once/Well/Fluid	Grab [1]
Free Oil [8.7.4]	No discharge		Once/Well/Fluid	Grab [1]
Oil-based Fluids[8.7.5]	No discharge		----	----
pH (SU) [8.7.6]	6.0 to 9.0		Once/Well/Fluid	Grab
TAH (µg/L) [8.7.7]	Report		Once/Well/Fluid	Grab
TAqH (µg/L) [8.7.7]	Report		Once/Well/Fluid	Grab
Chronic WET (TU_c) [8.7.8 and 8.9]	Report		Once/Well/Fluid	Grab

8.7.1 Discharge Frequency

Well completion, workover, treatment, and test fluids are not discharged continuously or regularly during the exploration drilling process. As such, the discharge frequency, number of discharge events during the month, is required to be reported on monthly DMRs for each separate fluid type discharged.

8.7.2 Flow

The Permit requires the permittee to record estimated or measured daily flow volumes consistently in a daily log and report the maximum daily volume during a given month in mgd on the DMR for each fluid type discharged. Daily logs must be kept onsite and made available upon request by DEC. Total flow volumes for each fluid type must be reported in the EOW Report. Flow measurements must be conducted over a 24-hour period and if the daily flow for a fluid discharge type exceeds 0.010 mgd the discharge qualifies for chronic WET testing per

Section 8.9 and permittee must collect one grab sample and conduct a to characterize the discharge.

8.7.3 Oil and Grease Limits

All completion, workover, treatment, and test fluids must be processed through and OWS, or other oil removal process, prior to discharge and samples must be collected after the final treatment step. Well completion, workover, treatment, and test fluid discharges must have no more than 42 mg/l of oil and grease in a given day and no more than 29 mg/l for any 30 day average. These values are to be reported per discharge type on the appropriate DMRs.

8.7.4 No Free Oil

The Permit includes a prohibition of the discharge of free oil for the well completion, workover, treatment, and test fluids discharge as demonstrated by passing the Static Sheen Test (EPA Method 1617).

8.7.5 Oil-Based Fluids

The Permit includes a prohibition of the discharge of oil-based fluids for the well completion, workover, treatment, and test fluids discharges.

8.7.6 pH.

The Permit includes a limit on pH of not less than 6.0 SU and not greater than 9.0 SU for completion, workover, treatment, and test fluid discharges. Samples must be collected downstream of the last treatment step prior to discharge.

8.7.7 TAH and TAqH Monitoring

The Permit requires monitoring for TAH and TAqH and reporting for information purposes. One grab sample must be collected from each well after the last treatment step for each separate fluid type discharged.

8.7.8 Chemical Inventory

For each fluid type discharged, the permittee must maintain a precise chemical inventory including the type and volume of all constituents added, including all completion, workover, treatment, and test fluid additives used and submit with the EOW Report.

8.8 Requirements for Hydrostatic Test Water (Discharge 020)

The permittee must comply with the effluent limitations and monitoring requirements in this section and in Table 50.

Table 50: Effluent Limitations and Requirements for Hydrostatic Test Water (Discharge 020)

Parameter (Units)	Effluent Limits	Monitoring Requirements	
		Frequency	Sample Type
Flow Volumes [8.8.1] (mgd)	Report	Daily	Estimate or Measured
pH (SU)	$6.5 \leq pH \leq 8.5$	Daily	Grab
Oil and Grease (Sheen) [8.8.2]	No Discharge	Daily	Visual
Turbidity (NTU)	25	Daily	Grab
TAH (µg/L) [8.8.3 and 8.8.4]	10	Per Discharge	Grab or Composite
TAqH (µg/L)) [8.8.3 and 8.8.4]	15	Per Discharge	Grab or Composite

8.8.1 Flow Volumes

Discharges or disposal of hydrostatic test water must be estimated or measured to determine daily flow volumes and be recorded in operating logs along with daily observations for sheen.

Daily logs must be kept onsite and made available upon request by DEC. Report daily maximum for the month on the DMR and total monthly volumes in the comments section.

8.8.2 Oil and Grease Visual

Once per discharge event, the permittee must observe the receiving water surface during a time when observation of the water surface is possible and record observations in a daily log maintained onsite. If conditions prevent observations, the permittee may use the Static Sheet Test (EPA Method 1617). Static Sheet Test equipment must be maintained onsite.

8.8.3 TAH and TAqH for New/Uncontaminated Infrastructure

TAH and TAqH monitoring is not required for all new/unused infrastructure (i.e. tanks, pipelines, or similar vessels) are not expected to have hydrocarbons (e.g., potable water systems per Section 8.8.5). In situations where new or unused infrastructure is being hydrostatically tested, TAqH and TAH shall be monitored if a visual sheen is detected in the discharge. If a sheen is detected, the permittee shall notify DEC within 24-hours, cease discharging, evaluate the source of the sheen, and collected a sample for TAH and TAqH. Based on information provided at the time, DEC may require specific BMPs for treatment devices to be implemented to prevent an oily sheen discharge (See Section 11.3.1.5).

8.8.4 TAH and TAqH for Existing Infrastructure Exposed to Hydrocarbons

Existing infrastructure that is known to have been in contact with petroleum is anticipated to have dissolved hydrocarbons and possibly free oil. The permittee can route potentially contaminated hydrostatic test water through produced water systems for treatment and discharge per Section 8.6.3. Alternatively, the permittee must implement BMPs per Section 11.3.1.5 to remove free and dissolved phase hydrocarbons prior to discharge. Compliance sampling for the TAH and TAqH limits can be achieved by collecting a single representative grab sample for volumes less than or equal to 500,000 gallons. Permittees discharging greater than 500,000 gallons must collect a composite sample of 8 grab samples collected at equal intervals during the discharge event as described in the QAPP.

8.8.5 Potable Water Discharges

Authorization of Hydrostatic Test Water includes discharges associated with flushing potable water systems and incidental discharges (e.g., leaks) that require repairs. In these instances, the permittee reports an estimated flow volume of the discharge on the DMR and indicates the volume is “potable water” in the comment section of the DMR. If the flush is to remove sediment from tanks and pipelines, the permittee must also monitor for turbidity and report results on the DMR along with a comment “potable water flush.”

8.9 Chronic WET Monitoring Requirements

If required per discharge-specific sections of the Permit, the permittee must conduct chronic WET testing per this section applying any unique considerations specified in discharge specific sections. For unique chronic WET considerations for Miscellaneous Discharges, See Section 8.5.5 and for unique chronic WET considerations for Produced Water Section 8.6.7.3.

8.9.1 Test Species and Methods

The permittee is required to conduct chronic WET testing on one vertebrate and one invertebrate species unless otherwise stated in discharge specific sections of the Permit. The permittee must conduct the WET testing to screen for the most sensitive invertebrate species in Section 8.9.1.2. The elimination of the less sensitive species over more sensitive invertebrate species must be approved by DEC in writing for use in subsequent chronic WET tests. Upon identification of the most sensitive test species, the permittee may submit a written request to eliminate the less sensitive species in subsequent WET analysis for DEC approval. DEC can

also approve written requests to substitute the less sensitive species during periods when the more sensitive species is unavailable. The permittee shall not make any changes to the selection of test species or dilution series without prior written DEC approval.

8.9.1.1 Vertebrate (survival and growth): *Atherinops affinis* (topsmelt). In the event that topsmelt is not available, *Menidia beryllina* (inland silverside) may be used as a substitute. The permittee shall document the use of substitute species in the DMR for the testing.

8.9.1.2 Invertebrate: For larval development tests, the permittee must use bivalve species *Crassostrea gigas* (Pacific Oyster) or *Mytilus spp*. (mussel) and *Americamysis bahia* (formally *Mysidopsis bahia*, mysid shrimp) for survival and growth. Due to seasonal variability, testing may be performed during reliable spawning periods (e.g., December through February for mussels and June through August for oysters).

8.9.2 Monitoring Frequency.

See discharge-specific sections for frequency requirements.

8.9.3 Procedures.

The permittee must conduct chronic WET testing using the following procedures.

8.9.3.1 Methods and Endpoints: For the shrimp and alternate fish species, inland silverside, the presence of chronic toxicity must be estimated as specified in *EPA Short-Term Methods for Estimating the Chronic Toxicity of Effluents and Receiving Waters to Marine and Estuarine Organisms, Third Edition* (EPA-821-R-02-014). For the bivalve species and topsmelt, chronic toxicity must be estimated as specified in *Short-Term Methods for Estimating the Chronic Toxicity of Effluents and Receiving Water to West Coast Marine and Estuarine Organisms* (EPA/600/R-95/136). The WET testing will determine the EC_{25} endpoint estimate of the effluent concentration that would cause a 25 % reduction in normal embryo development for the bivalves or in survival for fish and/or mysid shrimp. The WET testing will also determine the inhibition concentration (IC_{25}) point estimate of the effluent concentration that would cause a 25 % reduction in the growth of the fish and/or mysid shrimp.

8.9.3.2 Reporting Results: Results must be reported on the DMR using TU_c, where $TU_c = 100/EC_{25}$ or $100/IC_{25}$. The reported EC_{25} or IC_{25} must be the lowest point estimate calculated for the applicable survival, growth or normal embryo development endpoints. The permittee must report the no observed effect concentrations (NOECs) in the full WET test report. DEC may compare this information with the IC_{25} during reissuance of the Permit.

8.9.3.3 Acute Toxicity Estimates: Although acute WET testing is not required, the permittee must provide an estimate of acute toxicity based on observations of mortality when appropriate (e.g., vertebrates). Acute toxicity estimates, if available, must be documented in the full report.

8.9.3.4 Dilution Series: A series of at least five dilutions and a control must be tested. The recommended initial dilution series to screen for toxicity is 6.25, 12.5, 25, 50, and 75% along with a control of dilution water (0% effluent). In subsequent tests, the dilution series should be modified to bracket toxicity endpoints observed during previous tests. DEC may provide written direction to modify the previous dilution series or the permittee may request written approval from DEC to modify the dilution series based on previous test results.

8.9.3.5 Hold Times: WET sample holding times are established at 36 hours and samples must not exceed a hold time of 72 hours. The permittee must document the conditions that resulted in the need for the holding time to exceed 36 hours and the potential effect on the test results.

8.9.3.6 Additional Quality Assurance Procedures: In addition to those quality assurance measures

specified in the methodology, the following quality assurance procedures must be followed:

a) If organisms are not cultured by the testing laboratory, concurrent testing with reference toxicants must be conducted, unless the test organism supplier provides control chart data from at least the previous five months of reference toxicant testing. Where organisms are cultured by the testing laboratory, monthly reference toxicant testing is sufficient.

b) If either of the reference toxicant tests or the effluent tests does not meet all test acceptability criteria as specified in the test methods manual, then the permittee shall re-sample and re-test within the following month.

c) Control and dilution water must be receiving water, or salinity adjusted lab water. If the dilution water used is different from the culture water, a second control, using culture water must also be used.

8.9.3.7 WET Reporting.

8.9.3.8 DMRs and Full Report Deliverables: The permittee shall submit chronic WET test results on next month's DMR following the month of sample collection. The permittee must also submit the full WET Toxicity Report as an attachment to the DMR per Section 8.10.1

8.9.3.9 Full Report Preparation: The report of results shall include all relevant information outlined in Section 10 of Report Preparation in the U.S. EPA Short-Term Methods for Estimating the Chronic Toxicity of Effluents and Receiving Waters to Marine and Estuarine Organisms, Third Edition (EPA-821-R-02-014).

8.9.3.10 Additional Reporting Information: In addition to toxicity test results, the permittee shall report:

a) The date and time of sample collection and initiation of each test,

b) Facility production rate during sampling event,

c) The flow rate at the time of sample collection, and

d) A list of corrosion inhibitors, biocides, algaecides, clarifying agents, or other additives being used by facility that could potentially be in the effluent during the 30-day period preceding sampling.

8.10 Electronic Discharge Monitoring Reports

8.10.1 E-Reporting Rule, Phase I

The permittee must submit a DMR for each month by the 28th day of the following month. DMRs shall be submitted electronically through NetDMR per Phase I of the E-Reporting Rule (40 CFR 127). Authorized persons may access permit information by logging into the NetDMR Portal (http://cdxnodengn.epa.gov/oeca-netdmr-web/action/login). DMRs submitted in compliance with the E-Reporting Rule are not required to be submitted as described in Permit Appendix A – Standard Conditions unless requested or approved by the Department. Any DMR data required by the Permit that cannot be reported in a NetDMR field (e.g. mixing zone receiving water data, etc.), shall be included as an attachment to the NetDMR submittal. DEC has established an e-Reporting Information website (http://dec.alaska.gov/water/Compliance/EReportingRule.htm) that contains general information about this new reporting format. Training materials and webinars for NetDMR can be found at https://netdmr.zendesk.com/home.

8.10.2 E-Reporting Rule, Phase II (Other Reporting)

Phase II of the E-Reporting Rule specifies that permittees will integrate electronic reporting for all other reports required by the Permit (e.g., Annual Reports and Certifications) and

implementation is expected to begin around December 2020during the term of the Permit. Permittees should monitor DEC's E-Reporting website (http://dec.alaska.gov/water/Compliance/EReportingRule.htm) for updates on Phase II of the E-Reporting Rule and will be notified when they must begin submitting all other reports electronically. Until such time, other reports required by the Permit may be submitted in accordance with Permit Appendix A – Standard Conditions.

8.11 Monitoring Frequency Reductions

DEC has the authority to consider reduced reporting and monitoring frequencies in reissued permits when the permitted facilities has a record of good compliance and pollutant discharges at levels below permit requirements during the previous Permit cycle. DEC references *EPA Interim Guidance For Performance-Based Reduction of NPDES Permit Monitoring Frequencies* (*Frequency Reduction Guide*) to evaluate monitoring frequency reductions based on reporting and compliance during periods of review. The *Frequency Reduction Guide* uses statistically appropriate decision based on the observed ratio between long-term averages of the data to the AML. The data reviewed for produced water in Section 4.6.4 indicates that the frequency for all metals and WET monitoring could be reduced. However, DEC has decided not to reduce the frequencies upon the effective date of the Permit but to allow for reductions during the permit term as incentives to successfully implementing data quality improvement and PR strategies (See Sections 3.5.5, 8.5.4, and 8.6.7.2). Initially, all monitoring frequencies are the same as, or more frequent than, frequencies in the 2007 GP.

8.12 Additional Effluent Monitoring

DEC may require additional monitoring of effluent or receiving water for facility or site-specific purposes, including, but not limited to: obtaining data to support NOI or applications, demonstrating of water quality protection, obtaining data to evaluate ambient water quality, evaluating causes for elevated parameters in the effluent, and conducting chronic WET toxicity identification and reduction. If additional monitoring is required, DEC will provide the permittee or applicant the request in writing.

The permittee also has the option of taking more frequent samples than required under the Permit. These additional samples must be used for averaging if they are conducted using the Department approved test methods (generally found in 18 AAC 70 and 40 CFR 136 [adopted by reference in 18 AAC 83.010]). The results of any additional monitoring must be included in the calculation and reporting of the data on DMRs as required by the Permit and Standard Conditions Part 3.2 and 3.3 (Permit Appendix A).

Monitoring for effluent limitations must use methods with method detection limits that are less than the effluent limitations or are sufficiently sensitive. Monitoring effluent or receiving water for the purpose of comparing to water quality criteria must use methods that are less than the applicable criteria or are sufficiently sensitive. Per 40 CFR 122.21(a)(3), a method approved under 40 CFR 136 is sufficiently sensitive when:

(A) The method minimum level (ML) is at or below the level of the applicable water quality criterion for the measured parameter, or

(B) The method ML is above the applicable water quality criterion, but the amount of the pollutant or pollutant parameter in the discharge is high enough that the method detects and quantifies the level of the pollutant or pollutant parameter in the discharge (e.g., not applicable to effluent or receiving water monitored for characterization), or

(C) The method has the lowest ML of the analytical methods approved under 40 CFR 136 for the measured pollutant or pollutant parameter (e.g., the receiving water concentration or the criteria for a given pollutant or pollutant parameter is at or near the method with the lowest ML).

9.0 ANTIBACKSLIDING

Per 18 AAC 83.480, "effluent limitations, standards, or conditions must be at least as stringent as the final effluent limitations, standards, or conditions in the previous permit." Per 18 AAC 83.480(c), a permit may not be reissued "to contain an effluent limitation that is less stringent than required by effluent guidelines in effect at the time the permit is renewed or reissued."

Effluent limitations may be relaxed as allowed under 18 AAC 83.480, CWA 402(o) and CWA 303(d)(4). 18 AAC 83.480(b) allows relaxed limitations in renewed, reissued, or modified permits when there have been material and substantial alterations or additions to the permitted facility that justify the relaxation, or, if the Department determines that technical mistakes were made.

CWA 303(d)(4)(A) states that, for waterbodies where the water quality does not meet applicable WQS, effluent limitations may be revised under two conditions, the revised effluent limitation must ensure the attainment of the WQS (based on the waterbody TMDL or the waste load allocation) or the designated use which is not being attained is removed in accordance with the WQS regulations.

CWA 303(d)(4)(B) states that, for waterbodies where the water quality meets or exceeds the level necessary to support the waterbody's designated uses, WQBELs may be revised as long as the revision is consistent with the state's Antidegradation Policy. Even if the requirements of CWA 303(d)(4) or

18 AAC 83.480(b) only applies to effluent limitations established on the basis of CWA 402(a)(1)(B), and modification of such limitations based on effluent guidelines that were issued under CWA 304(b). Accordingly, 18 AAC 83.480(b) applies to the relaxation previously established case-by-case TBELs developed using BPJ. To determine if backsliding is allowable under 18 AAC 83.480(b), the regulation provides five regulatory criteria (18 AAC 83.480[b][1-5]) that must be evaluated and satisfied.

All effluent limitations, standards, and conditions in the Permit are as stringent, or more stringent, than those in the 2007 GP except for removal of chronic WET limits and associated accelerated testing and TRE/TIE requirements for produced water. The WET limits were also used as triggers for accelerated testing (limit/triggers). Removal of the chronic WET limit/triggers is allowable based on the current reasonable potential analysis. Because there is no reasonable potential for the discharge to exceed, or contribute to an exceedance, of chronic WET criteria at the boundary of the chronic mixing zone, a limit for chronic WET is not required per 18 AAC 83.435(e) or 18 AAC 70.030(a). Per CWA 402(o)(1), backsliding is allowable as long as it does not violate an ELG and complies with WQS including the Antidegradation Policy per CWA 303(d)(4). See Section 10.4.3.2 for further discussion.

The removal of accelerated testing and TRE/TIE requirements is allowable based on new information that was not previously available per 40 CFR 122.44(l)(2)(i)(B)(1), new toxicity data that provided more accurate characterization of the effluent. As structured in the 2007 GP, the accelerated testing and TRE/TIE requirements were not effective. The triggers in the 2007 GP were based on data that were generally biased high due chronic WET test results that did not achieve observation of endpoints because the test dilution series were too low to target toxicity such that triggers would never be initiated (See Section 4.6.5). The new chronic WET data were significantly lower in comparison to the data that was used to formulate the limit/triggers in the 2007 GP. Given DEC used the same methodology but with new data to develop notification levels, the new data represents new information that, if known previously, would have resulted in lower toxicity limit/triggers. Because the new lower

chronic WET notifications are not established based on authorized chronic dilution in the mixing zone, imposition of accelerated testing or TRE/TIE is not warranted because exceeding water quality criteria at the boundary of the mixing zone is not a consideration. Nonetheless, DEC imposes notification levels as a means to ensure chronic toxicity continues to be at low levels. If the notification level is exceeded, a follow up sample must be collected within 30 days instead of two weeks as in the 2007 GP. If the additional sample is also above the trigger, DEC has the authority under Permit Section 2.11.2.3 to require additional monitoring to evaluate the cause of elevated toxicity. In addition, DEC modified the chronic WET dilution series to result in collecting meaningful data for the purpose of characterizing the effluent. No water quality impacts are anticipated because the new approach targets appropriate triggers, does not eliminate DEC authority to conduct TRE and TIE, and implements RP reduction strategies to reduce or eliminate pollutants. Hence, the removal of the chronic WET limit/triggers, accelerated testing, TRE, and TIE requirements complies with WQS including the Antidegradation Policy per 40 CFR 122.44(l)(2)(ii). See Section 10.4.3.2 for further discussion.

10.0 ANTIDEGRADATION

10.1 Legal Basis

Section 303(d)(4) of the CWA states that, for waterbodies where the water quality meets or exceeds the level necessary to support the waterbody's designated uses, WQBELs may be revised as long as the revision is consistent with the State's Antidegradation Policy and implementation methods. Alaska's current Antidegradation Policy and Implementation Methods are presented in 18 AAC 70.015 Antidegradation Policy and in 18 AAC 70.016 Antidegradation Implementation Methods for discharges authorized under the federal Clean Water Act. The Antidegradation Policy and Implementation Methods have been amended through April 6, 2018, are consistent with 40 CFR 131.12, and were approved by EPA on July 26, 2018.

The following subsections document the Department's conformance with the Policy and Implementation Methods for reissuance of the Permit.

10.2 Receiving Water Status, Tier Determination, and Analysis Requirements

Per the Implementation Methods, the Department determines a Tier 1 or Tier 2 classification and protection level on a parameter by parameter basis for the waterbody. The Implementation Methods also describe a Tier 3 protection level applying to designated waters, although at this time no Tier 3 waters have been designated in Alaska.

The marine waters of Cook Inlet, covered under the Permit, are not listed as impaired (Categories 4 or 5) in the *Alaska's Final 2010 Integrated Water Quality Monitoring and Assessment Report*. Therefore, no parameters have been identified where only the Tier 1 protection level applies. Accordingly, this antidegradation analysis applies the Tier 2 protection level on a parameter by parameter basis consistent with 18 AAC 70.016(c)(1) and 18 AAC 70.015(a)(2) that states if the quality of water exceeds levels necessary to support propagation of fish, shellfish, wildlife, and recreation in and on the water, that quality must be maintained and protected, unless the Department authorizes a reduction in water quality. Prior to authorizing a reduction of water quality, the Department must first analyze and confirm the findings under 18 AAC 70.015(a)(2)(A-D) are met. Because Tier 1 protection applies to all waters of the U.S. in the state, the analysis must be conducted with implementation procedures in 18 AAC 70.016(b)(5)(A-C) for Tier 1 protection. For Tier 2 protection, the analysis must also comply with 18 AAC 70.016(c)(7)(A-F). Lastly, because this antidegradation analysis is for a general permit, 18 AAC 70.016(e) also applies. These analyses and associated finding are summarized below.

10.3 Tier 1 Analysis of Existing Use Protection

The summary below presents the Department's analyses and findings for the Tier 1 analysis of existing use protections per 18 AAC 70.016(b)(5) finding that:

(A) existing uses and the water quality necessary for protection of existing uses have been identified based on available evidence, including water quality and use related data, information submitted by the applicant, and water quality and use related data and information received during public comment;

The Department reviewed water quality data, environmental monitoring studies, and information on existing uses within the coverage area. The Department finds the information reviewed as sufficient and credible to identify existing uses and water quality necessary for Tier 1 protection.

(B) existing uses will be maintained and protected; and

Per 18 AAC 70.020 and 18 AAC 70.050, marine waters are protected for all uses. Therefore, the most stringent water quality criteria found in 18 AAC 70.020 and in *the Alaska Water Quality Criteria Manual for Toxic and Other Deleterious Organic and Inorganic Substances, 2008 (Toxicity Manual*) apply and were evaluated to ensure existing uses and the water quality necessary for protection of existing uses of the receiving waterbody are fully maintained and protected. Water quality criteria are developed to be protective of existing uses. The discharges authorized under the Permit are controlled or limited to either meet criteria at the point of discharge or at the boundary of the chronic mixing zone, if applicable. Given water quality criteria is met at the boundary of the chronic mixing zone for all parameters, the existing uses of the waterbody as a whole are being maintained and protected.

(C) the discharge will not cause water quality to be lowered further where the department finds that the parameter already exceeds applicable criteria in 18 AAC 70.020(b), 18 AAC 70.030, or 18 AAC 70.236(b).

As discussed in (B), the Permit has been developed to ensure discharges shall not cause or contribute to an exceedance of water quality criteria. As previously stated, the marine waters of Cook Inlet covered under the Permit are not listed as impaired. Therefore, no parameters were identified as already exceeding the applicable criteria in 18 AAC 70.020(b) or 18 AAC 70.030.

The Department concludes the terms and conditions of the Permit will be adequate to fully protect and maintain the existing uses of the water and that the findings required under 18 AAC 70.016(b)(5) are met.

10.4 Tier 2 Analysis for Lowering Water Quality

10.4.1 Scope of Tier 2 Analysis

Per 18 AAC 70.016(c)(2), an antidegradation analysis is required for those waterbodies needing Tier 2 protection and which have any new or existing discharges that are being expanded based on permitted increases in loading, concentration, or other changes in effluent characteristics that could result in comparative lower water quality or pose new adverse environmental impacts. Per 18 AAC 70.016(c)(2)(A), the analysis will only be conducted for the portion of the discharge that represents an increase from the existing authorized discharge. Additionally, per 18 AAC 70.016(c)(3), DEC is not required to conduct an antidegradation analysis for a discharge that is not expanding.

Per 18 AAC 70.990(75), "new or expanded" with respect to discharges means discharges that are regulated for the first time or discharges that are expanded such that they could result in an increase in pollutant load or concentration or other changes in discharge characteristics that could lower water quality or have other adverse environmental impacts. The determination of

expanding can take on different contexts depending on whether the permit is an individual permit or a general permit. Individual permits are specific to a single facility such that a new or expanded discharge is relatively easy to define. Whereas, because general permits cover multiple discharge categories for an undefined number of facilities, determining what constitutes a new or expanded discharge is more complicated.

10.4.1.1 Discharges Meeting the Definition of New or Expanded

The determination of "new or expanded" is complicated when evaluating the requested new authorization of produced water under the Permit by CIE for the Osprey Platform. Under an individual permit, it would be considered a new discharge. However, given the 2007 GP included the discharge of produced water, it is unclear that the CIE discharge of produced water meets the definition of a new discharge or expanded discharge under the Permit. Under the 2007 and current Permit, each individual facility is limited by the same parameters but at different concentrations based on the facility-specific characteristics of the produced water being discharged. Although the Osprey did not have facility-specific concentration limits in the 2007 GP, the limited parameters in the Permit are consistent with the 2007 GP, which suggests the discharge of produced water is not expanding. However, when comparing the flow limitations between the 2007 GP and the current Permit, there has been an increase in total permitted flows of produced water; although the Anna Platform is no longer seeking authorization to discharge, the requested discharge flow rate from the Osprey is greater than the flow vacated by discontinuance of the Anna Platform (See Section 4.6.3). Hence, the permitted flows under the Permit have increased as a result of the Osprey discharge of produced water. Given there is a slight increase in flows being authorized and an antidegradation analysis would be required under an individual permit, DEC is conducting an antidegradation analysis for the discharge of produced water from the Osprey Platform for reissuance of the Permit. The evaluation is limited to only the discharge of produced water and the permitted parameters from the Osprey Platform, which include oil and grease, pH, TAH and copper. DEC considers this a unique circumstance and is applying the antidegradation analysis to be transparent and this approach may not be applicable for other general permits or circumstances.

10.4.1.2 Discharges Not Meeting the Definition of New or Expanded

In the context of the Permit, there are no increases in permitted loads or concentrations to existing, previously regulated discharges other than for produced water per Section 10.4.1.1. All of the limitations have stayed the same or have decreased in the Permit. Although the discharge of drilling fluids and drill cuttings now encompasses non-oil and gas activities, there are no increases in permitted load or concentrations; the geotechnical survey or HDD discharges generally have the same characteristics, or better, as oil and gas discharges and have similar limitations when applicable. Although the Permit includes a new discharge category for hydrostatic test water (Discharge 020), hydrostatic test water was previously included in the 2007 GP under the definition of produced water (i.e., an allowable commingled source). The ability to commingle hydrostatic test water with produced water is retained in the Permit and if the hydrostatic test water is not commingled with produced water, it must meet water quality criteria at the point of discharge. Hence, the discharge is not new nor has the permitted concentration expanded.

10.4.2 Tier 2 Analysis

The policy in 18 AAC 70.015(a)(2) states that if the quality of water exceeds levels necessary to support propagation of fish, shellfish, wildlife, and recreation in and on the water (i.e., Tier 2 waters), that quality must be maintained and protected. The Department may allow a reduction of water quality only after finding that the most practicable and effective pollution prevention, control, and treatment methods are being used such that lowering of water quality is necessary.

Upon making this determination, the specific requirements of the policy noted in 18 AAC 70.015(a)(2)(A)-(D) must be met. The Department's findings are presented below.

10.4.2.1 Tier 2 Alternatives Analysis

As discussed in Section 4.6.4.8, the Osprey has not demonstrated the ability to meet oil and grease ELGs based on the six samples collected to support their application. DEC requested an alternatives analysis to support their application and this antidegradation analysis. Per 18 AAC 70.016(c)(4)(C-F), the applicant must submit a description and analysis of a range of practicable alternatives that have the potential to prevent or lessen the degradation associated with the expanded discharge. The analysis must identify the water quality environmental impacts and relative costs for each practicable alternative. CIE submitted their analysis on August 10, 2018. DEC has reviewed and this submittal and has determined it is sufficient for Department review.

The KPF currently provides primary treatment that includes chemical addition to demulsify, free water knockout vessels, coalescers, and skimmers. CIE evaluated five alternatives for improving treatment performance and reducing environmental impacts to the receiving water:

1. no discharge via injection,
2. single port diffuser,
3. multi-port diffuser,
4. secondary treatment consisting of induced gas flotation (IGF), and
5. tertiary treatment consisting of nutshell filtrations.

The alternative of injection of produced water was eliminated as being technically infeasible as well as cost prohibitive and make CIE competitively disadvantaged with other Cook Inlet producers (EPA 1996). Assuming similar subsurface conditions exist at the KPF location as that at nearby TBPF, the non-oil producing formations beneath the KPF are inadequate for the volume to be injected. Furthermore, injecting into the oil-producing formation is no longer practicable and would eliminate several currently producing oil production wells (See Section 2.2.8). The cost of installing injection wells, if not technically infeasible, is up to $5,000,000.

A single port versus multiport analysis was conducted to determine the benefits of optimizing mixing in Cook Inlet and reduce the size of the proposed mixing zone (i.e., increase environmental protection). The cost of installing a single port is approximately $2,000,000 and the additional cost of installing a multiport diffuser was negligible as the majority of the cost is associated with installing the main line.

IGF meets the model technology requirements for the ELGs to attain the oil and grease limits as well as reduce metals and dissolved hydrocarbons, TAH and TAqH, in the final effluent. The anticipated effluent quality would be similar to existing facilities discharging under the Permit. The cost of installing four IGF units is estimated to range from $300,000 to $550,000.

Nutshell filtration was evaluated as tertiary treatment to further reduce TAH and TAqH. Although the installation of nutshell filters would provide superior environmental benefits, there would significant cross-media environmental impacts and costs to replenish spent media. These additional environmental impacts cost is not justifiable given the IGF alternative meets regulatory requirements without cross-media environmental impacts.

The proposed alternative is to install four parallel IGF units downstream of the existing primary treatment system and discharge through a multiport diffuser. This alternative would meet regulatory requirements and place CIE on par with other Cook Inlet producer treatment systems. The multiport diffuser ensures the discharge meets water quality criteria effectively in the receiving water. DEC agrees that the IGF and multiport alternative provides the most practicable and effective method of pollution prevention, control, and treatment but would also

require some lowering of water quality under 18 AAC 70.015(a)(2)(A).

10.4.3 Basis for Reduction of Water Quality

Based on the above finding, the Department can authorize a reduction in water quality only after the applicant has submitted evidence in accordance with the following requirements under 18 AAC 70.015(a)(2)(A – D):

10.4.3.1 Accommodation of Important Social or Economic Develop in the Vicinity

(A) Allowing lower water quality is necessary to accommodate important economic or social development in the area where the water is located.

The ability for CIE to discharge produced water at the Osprey Platform has an economic benefit statewide and down to the local area of operation. Maintaining oil production in Cook Inlet is vital to the economic recovery and sustainability due to low oil prices and helps prevent additional layoffs in a difficult economy.

Oil and Prices and Employment: In 2014, oil prices began to drop rapidly which lead to an immediate drop in revenue for the State of Alaska. In early 2015, as the price of oil fell below $40 per barrel, the State government began to cut jobs and capital projects in a measure to reduce expenses. The oil and gas industry maintained high employment through 2014 but the continued drop in oil prices through 2015 and into 2016 prompted rapid job cuts. In 2016, the oil and gas service industry lost 2,900 jobs, professional services were reduced by 1,600 jobs, the construction sector lost 1,400 jobs, and the State government shrank by 1,200 jobs (Alaska Department of Labor and Workforce Development [ADLWD] 2018). By 2017, the price of oil began to rebound (averaging $50 per barrel); however, the oil and gas industry and state government still eliminated approximately 3,600 jobs to offset revenue reductions. As the price of oil continues to increase in 2018 and initial planning begins for many new oil and gas projects, further job cuts are expected to slow down (ADLWD 2018).

Authorization to discharge produced water would allow CIE to immediately increase production by 250 to 500 bbl/day through increased well pumping rates without increasing disposal well capacity. In addition to the increase in well production, the discharging produced water would facilitate CIE to invest in drilling and developing additional new wells in Cook Inlet over the next 3 to 5 years. This is estimated to add an additional 2,000 bbl/day to production. Consequently, a direct increase in work force would also result from these new production wells coming on line (See Kenai Peninsula Borough discussion below). Alternatively, an inability to discharge produced water will result in reduced production associated reductions in workforce.

Statewide: The Alaska Oil and Gas Association (AOGA) assesses the economic impact of the oil and gas industry on Alaska's private and public-sectors (McDowell 2017). The latest 2016 analysis presents the 14 primary oil and gas companies' economic contribution to the State of Alaska. Glacier Oil and Gas (operates as CIE in the Cook Inlet) was one of the 14 companies included in the research and one of the few that operates solely in Alaska. The following lists the social and economic impacts the oil and gas industry has statewide in Alaska:

- In 2016, the 14 primary oil and gas companies directly employed 4,275 Alaska residents, indirectly supported another 6,095 Alaskan employees in the oil and gas support sector, and spent approximately $4.6 billion in operating and capital expenditures with approximately 1,000 Alaskan vendors.
- Direct, indirect and induced jobs supported by the Alaska oil and gas industry totaled 45,575 jobs and $3.1 billion in wages.

- State and local royalties and taxes paid by the Alaska oil and gas sector directly and indirectly creates approximately 58,300 jobs and generates $2.9 billion in wages.
- In total, the Alaska oil and gas sector directly and indirectly supported a total of 103,875 jobs in Alaska and paid $6 billion in wages.
- Regionally, the 14 primary oil and gas companies impact jobs and wages in the Municipality of Anchorage, the Kenai Peninsula Borough, and the Matanuska-Susitna Borough.

Anchorage: In Anchorage, the industry directly employees approximately 2,265 employees and accounts for $409 million in annual wages. In addition, an estimated 2,025 oil and gas support services employees reside in Anchorage with annual wages of $220 million. Additionally, 24,050 indirect jobs in Anchorage are connected to the oil and gas industry in Alaska. Wages spent by employees supporting the oil and gas industry create even more jobs and income in Anchorage (induced impacts). In total, these jobs accounted for approximately $1.2 billion in annual wages in Anchorage.

Matanuska-Susitna Borough (MSB): In the MSB, oil and gas has 515 direct employees and accounts for $89 million in wages; additionally, 1,580 oil and gas support service jobs total $144 million in wages. Although few industry related jobs are located in the MSB, for all direct, indirect, and induced effects, the oil and gas industry accounted for an annual average of 3,270 jobs in Mat-Su and total annual payroll of $287 million.

Kenai Peninsula Borough (KPB): In the KPB, oil and gas has 810 direct employees and accounts for $142 million in wages. Additionally, 1,615 support service jobs provide $153 million in wages. Six of the top 10 business taxpayers in the KPB are oil and gas companies; this includes CIE. Currently CIE employs approximately 40 full-time personnel within Cook Inlet.

Limiting disposal to injection means CIE is limited economically to the volume of produced water that can be injected. As a result of obtaining authorization to discharge produced water, CIE investment of new production wells is estimated to directly employ up to six year-round and 117 seasonal full-time positions. Table 51 provides a summary provided by CIE on anticipated labor increases.

Table 51: Projected Induced Employment

Job Description	Number of Full-time Positions
Year-Round Positions	
Administrative and Management	2
Production/Maintenance	4
Seasonal Positions	
Exploration Drilling	50
Completion Operations	5
Logistical Support (air/marine)	12
Contractors	50

The Department finds that the social or economic benefit in the vicinity of the discharge is met.

10.4.3.2 Reducing Water Quality Will Not Violate Applicable Criteria

(B) Except as allowed under this subsection, reducing water quality will not violate the applicable criteria of 18 AAC 70.020 or 18 AAC 70.235 or the whole effluent toxicity limit in 18 AAC 70.030.

18 AAC 70.020(b) specifies the State's protected water use classes, subclasses, and water

quality criteria necessary to ensure protection of these uses. The Permit includes authorization of a rectangular chronic mixing zone that is 1,060 meters long (530 meters in each prevailing current direction) by 348 meters wide. The mixing zone was appropriately sized using updated CORMIX software and newly available data for the multiport diffuser discussed in Section 6.2.3.6.8 such that all water quality criteria will be met at, and beyond, the boundary of this chronic mixing zone. Accordingly, this requirement has been met.

18 AAC 70.020 refers to development of site-specific water quality criteria as listed in 18 AAC 70.036. Although there are site-specific criteria established for metals near Point Woronzoff, the specified location of this site-specific criteria is outside of the coverage area of the Permit and the vicinity of the Osprey located south of the Forelands. Hence, the discharge will not violate this site-specific criteria and this requirement is met.

18 AAC 70.030(a) applies to WET limits and requires that an effluent discharged to a water may not impart chronic toxicity to aquatic organisms, expressed as 1.0 TUc, at the point of discharge, or if the department authorizes a mixing zone in a permit at or beyond the mixing zone based on the minimum effluent dilution achieved in the mixing zone. Chronic WET is one of the authorized mixing zone parameters for Outfall 001 (See Section 6.2.3.6.8) but no limit is required. The chronic mixing zone is authorized to have a chronic dilution factor of 800. The observed toxicity is 63.29 TUc, and the toxicity that would result in reasonable potential at the boundary of the authorized chronic mixing zone require a limit is 800 TUc. A similar evaluation of chronic WET requirements was applied to all discharges of produced water under the Permit. Given none of the maximum expected chronic WET levels can be projected to exceeded the water quality criteria of 1 TU_c at the boundary of the chronic mixing zones for each discharge (compare the chronic dilution factors in Table 27 to the chronic WET notification levels in Table 48), removal of the limit/triggers, accelerated testing, TRE, and TIE requirements is appropriate (See Section 4.6.5). Hence, no chronic WET limits are being imposed in the Permit and the requirements of 18 AAC 70.030(a) are met.

10.4.3.3 Tier 1 Protection of Existing Uses

(C) The resulting water quality will be adequate to fully protect existing uses of the water.

As discussed in part (B) of the preceding Tier 1 analysis, marine waters are protected for all uses and all water quality criteria developed to protect these uses are met at the boundary of the chronic mixing zone for produced water. Hence, this finding has been met.

10.4.3.4 All Wastes and Other Substances Discharged Will be Treated and Controlled

(D) All wastes and other substances discharged will be treated and controlled to achieve (i) for new and existing point sources, the highest statutory and regulatory requirements...

The applicable "highest statutory and regulatory treatment requirements" are defined in 18 AAC 70.015(d). The definition includes the four components noted below:

(*1) Any federal technology-based effluent limitation identified in 40 CFR. 122.29 and 125.3, revised as of July 1, 2017 and adopted by reference;*

EPA promulgated 40 CFR 435 Subpart D in 1996, as adopted in 18 AAC 83, and determined that discharges of produced water to Cook Inlet are appropriately controlled through ELGs for oil and grease; MDL of 42 mg/L and AML of 29 mg/L. Prior to the Osprey Platform obtaining authorization to discharge under the Permit, successful implementation of the alternative analysis will be required. The applicant must submit plans to the Department under 18 AAC 72 to ensure the treatment will meet the treatment requirements for the Permit as reflected by the model technology assumptions in the ELG. In addition to the TBEL established through the ELG, DEC also imposes a TBEL using case-by-case BPJ for pH.

(2) any minimum treatment standards identified in 18 AAC 72.050;

This part of the definition addresses the minimum treatment standards for domestic wastewater discharges. Per 18 AAC 72.050(a)(4) domestic wastewater discharges into the waters of the US must have received secondary treatment prior to discharge. Given the new or expanded discharge being evaluated is not domestic wastewater, this requirement does not apply.

(3) any treatment requirements imposed under another state law that is more stringent than a requirement of this chapter; and

This part of the definition includes any treatment required by state law that is more stringent than 18 AAC 70. Other regulations beyond 18 AAC 70 that may apply to this permitting action include 18 AAC 15 and 18 AAC 83. The Permit is consistent with 18 AAC 83 and neither the regulations in 18 AAC 15, nor any other state legal requirement that the Department is aware of, impose more stringent treatment requirements than 18 AAC 70. Therefore, this part of the definition is met.

(4) any water quality-based effluent limitations established in accordance with 33 USC 1311(b)(1)(C)(Clean Water Act, sec. 301(b)(1)(C).

Alaska water quality criteria are presented in 18 AAC 70.020 and the *Water Quality Criteria for Toxics and Other Deleterious Substances* amended through December 12, 2008 (*Toxics Manual*). WQBEL limits have been established to be more stringent than applicable TBELs per the a *Reasonable Potential Analysis and Effluent Limits Development Guide*, June 30, 2014 (*RPA/WQBEL Guidance*), which complies with 18 AAC 83.435 and CWA 301(b)(1)(C). The Permit imposes WQBEL for TAH (MDL of 9.0 mg/L and AML of 7.7 mg/L) and for copper (MDL of 195 µg/L and AML of 97 µg/L). During development of these WQBELs, DEC used ambient data collected from ICIEMAP that provided information on the existing water quality and potential contributions of pollutants in nonpoint sources and other point sources discharging within the area of coverage. For TAH, no TAH concentrations were observed in the ambient receiving water. For copper, an ambient concentration of 0.926 µg/L representing the 85th percentile of the data collected was used in the WQBEL development.

Per 18 AAC 70.016(c)(7)(C), DEC must consider other point sources and state-regulated non-point sources discharging to the waterbody that could impact water quality and if there are any outstanding compliance issues with point source permits or BMPs for non-point sources. In this fourth finding, DEC identifies all the discharges in the Permit and discharges from the following seven permitted point sources that have limits for oil and grease, TAH, pH, or copper:

- AK0000396 – Cook Inlet Pipeline Company, Drift River Terminal
- AK0000507 – Agrium Inc., Kenai Plant
- AK0000841 – Tesoro Alaska Petroleum Company, Kenai Refinery
- AK0001155 – Kenai LNG Corporation, Kenai LNG Facility
- AK0026603 – Chugach Electric Association, Beluga Power Plant
- AK0053619 – Alaska Electric and Energy Coop., Nikiski Combined Cycle Plant
- AKG003025 – Hilcorp Alaska, LLC, DRT 30-inch Pipeline Cook Inlet
- AKG003026 – Harvest Alaska, LLC, Cook Inlet Pipeline Extension

In review of these individual permits, DEC found no outstanding compliance issues that affect the antidegradation analysis. For state-regulated non-point sources, DEC considered several contaminated sites in the vicinity of the Nikiski industrialized area (e.g., refinery,

LNG, power plant, fertilizer plant) that have plumes that enter Cook Inlet through groundwater. These sources are regulated by the DEC CSP and require continued monitoring of plume attenuation. With respect to these point source and non-point sources, DEC indicates that none of the receiving water samples collected by ICIEMAP and reported in the PWS Report detected concentrations of TAH. In addition, the 85th percentile concentration for copper is 0.926 mg/L, which is below the chronic marine water quality criteria for copper. This information supports the finding that discharges from new and existing point sources meet the highest statutory and regulatory requirements. In addition, is supports the finding that all cost-effective and reasonable BMPs are being applied to non-point sources. Therefore, DEC concludes that the fourth finding is met.

Per the aggregate findings in Sections 10.4.3.1 through 10.4.3.4, DEC determines that the applicant has submitted sufficient evidence for the Department to authorize lowering of water quality associated with the discharge of produced water from the Osprey Platform.

11.0 OTHER PERMIT CONDITIONS

11.1 Standard Permit Provisions

Appendix A of the Permit contains standard regulatory language that must be included in all APDES permits. These requirements are based on the regulations and cannot be challenged in the context of an individual APDES permit action. The standard regulatory language covers requirements such as monitoring, recording, reporting requirements, compliance responsibilities, signatory authority, and other general requirements.

11.2 Quality Assurance Project Plan

The permittee is required to develop procedures to ensure that the monitoring data submitted are accurate and to explain data anomalies if they occur. The permittee is required to develop QAPP and submit a letter to the Department stating that the plan has been implemented within 90 days of the effective date of the Final Permit for existing facilities or the date of the authorization for new facilities. The QAPP shall consist of standard operating procedures the permittee must follow for collecting, handling, storing and shipping samples; laboratory analysis; and data reporting. In addition, the QAPP must specifically define sampling procedures specifically developed for the collection of chronic WET samples for the miscellaneous discharges of Desalination Waste (Discharge 005), Noncontact Cooling Water (Discharge 009) and Waterflooding (Discharge 014) that will result in collection of samples representing probable maximum batch chemical dosing concentrations at the sample port (See Section 8.5.5.5). The plan shall be retained on site and made available to the Department upon request.

11.3 Best Management Practices

A BMP Plan is a collection of pollution control methods and housekeeping measures which are intended to minimize or prevent the generation and the potential release of pollutants from a facility to the waters of the U.S. through normal operations and ancillary activities. Per CWA 402(a)(1), development and implementation of BMPs may be included as a condition in APDES permits. CWA 402(a)(1) authorizes DEC to include miscellaneous requirements that are deemed necessary to carry out the provision of the CWA in permits on a case-by-case basis. The BMP Plan must be developed to control, or abate, the discharge of pollutants in accordance with 18 AAC 83.475. A BMP Plan must include certain generic BMPs as well as specific BMPs for controlling pollutants (See Section 11.3.1).

Within 90 days of the effective date of the Permit, the permittee must be revise and implement the BMP Plan. Upon revising the BMP Plan, the permittee must submit written certification that

the BMP Plan has been revised and implemented within 90 days of the effective date of the Permit. In subsequent years of the Permit, the permittee must establish a review committee to review and revise the BMP Plan annually to include any modifications deemed to be necessary or appropriate since the previous revision to meet the objectives and specific requirements in the Permit. By January 31st of each year thereafter, the permittee must submit written certification that the BMP Plan review committee has reviewed and modified the BMP Plan, as appropriate.

11.3.1 Specific BMPs

11.3.1.1 BMPs for Deck Drainage

The permittee must develop and implement BMPs for separating area drains for wash-down and rainfall that may be contaminated with oil and grease from those area drains that would not be contaminated so that the waste streams are not comingled. Deck drainage that is contaminated with oil and grease must be processed through an oil-water separator, or other similar treatment process, prior to discharge.

11.3.1.2 BMPs for Graywater

Per Section 8.4.5, permittees shall develop and implement housekeeping BMPs which ensure: discharges do not contain floating solids, foam or garbage; the use of phosphate free and non-toxic soaps and detergents; minimal use of chlorine and other disinfections products; chemical cleaning compounds and disinfectants used will minimize the addition of nitrogen and phosphorous-based chemicals; chemical cleaning compounds and disinfectants are applied in accordance with manufacturer's instructions; kitchen oils are not introduced to the graywater system. In addition, for discharges of graywater treated using an MSD the permittee must develop and implement operation and maintenance BMPs that ensure consistent and effective dechlorination to achieve the 1.0 mg/L TRC limit.

11.3.1.3 BMPs for Miscellaneous Discharges Potentially Contaminated with Oil

Per Section 8.5.2, specific BMPs must be developed and implement to support the prohibition of free oil for the following miscellaneous discharges:

- Discharge 006 - Blowout Preventer Fluid
- Discharge 010 - Uncontaminated Ballast Water
- Discharge 012 - Excess Cement Slurry
- Discharge 013 - Fluids, Cuttings, and Cement at the Seafloor

11.3.1.4 Miscellaneous Discharges 005, 009 and 014 Pollution Reduction BMPs

Per Section 8.5.4, DEC requires that the BMP Plan include a specific BMP to optimize the use of chemicals (e.g., a chemical-dosing matrix) and to minimize the potential for chronic toxicity in discharges of desalination waste (Discharge 005), noncontact cooling water (Discharge 009) and waterflooding (Discharge 014) that are required to monitor for chronic WET. Upon exceeding chronic WET PR BMP Revision Action Levels, the permittee must modify this specific BMP to include BMP revisions to reduce subsequent chronic toxicity to below the PR BMP Revision Action Levels. Examples of BMP revisions include, but are not limited to revamping the chemical dosing matrix or injection practices; substitution of less toxic chemicals; eliminating, reducing, or controlling spikes resulting from batch dosing; or alternative disposal options. BMPs must continue to be revised until the chronic WET PR BMP Revision Action Levels are attained. If the BMP revision involves significant physical changes to the treatment and disposal system, the permittee must describe these modifications in submittals required in Section 8.5.4and submit update line diagrams reflecting these modifications with the next application for reissuance.

11.3.1.5 Hydrocarbon Treatment BMPs for Hydrostatic Test Water

If a visual sheen is detected in the discharge of hydrostatic test water, the permittee shall notify DEC per Section 8.8.3. Based on information provided at the time, DEC may require specific BMPs for treatment devices to be implemented to prevent an oily sheen discharge or exceedance of TAH and TAqH limits. For infrastructure that has known to been in contact with petroleum and is anticipated to have dissolved hydrocarbons and possibly free oil, the permittee must implement BMPs to remove free and dissolved phase hydrocarbons prior to discharge per Section 8.8.4. However, this specific BMP requirement is not subject to commingling with produced water per Section

11.3.1.6 Cooling Water Intake Structure Requirements.

The Permit incorporates the 2006 regulation, 40 CFR Part 125, Subpart N adopted by reference at 18 AAC 83.010(c)(9) (CWIS regulations), that requires new offshore oil and gas facilities to take measures to reduce entrainment and impingement of aquatic life associated with the construction and operation of CWIS. The CWIS regulation was promulgated to ensure that the location, design, construction, operation and capacity of CWIS reflect the best technology available to minimize adverse impacts to aquatic organisms.

The CWIS regulations apply to new facilities (facilities that commence construction after July 17, 2006), is a point source discharge, intake 2 million gallons per day of water, and use at least 25 % of that water for cooling. Per CFR regulations adopted by reference, the owner or operator of a new offshore oil and gas extraction facility must comply with: (i) Track I in 40 CFR Part 125.134(b) or Track II in 40 CFR Part 125.134(c) if it is a fixed facility; or (ii) Track I in 40 CFR Part 125.134(b) if it is not a fixed facility (i.e. non-fixed facility). Because the Permit applies only to mobile exploration facilities (e.g., drill ships, temporarily moored semi-submersibles, jack-ups, submersibles, tender-assisted rigs and drill barges), facilities authorized under the Permit must comply with Track I requirements (See Appendix H of the Permit)

Per CWIS regulations, the Department may impose requirements on a case-by-case basis using BPJ for those new facilities that do not meet the threshold requirements regarding the amount of water withdrawn or percentage of water withdrawn use for cooling water purposes.

The Permit requires the permittee to select and implement technologies or operational measures to minimize impingement mortality and entrainment of fish and shellfish and include this information in the BMP Plan. The BMP Plan requirement gives the permittee discretion on what methods to select and how to implement those methods. However, the Department retains the authority to impose more stringent conditions on a case-by-case basis, if such conditions are deemed necessary by the Department to comply with any provision of law in accordance with the Permit.

Per CWIS regulations, DEC can require the implementation of additional technologies and operational measures if there is information indicating the potential for specified aquatic organisms to pass through the hydraulic zone of influence of the facility's cooling water intake structure. Note that the BMP Plan is required to be submitted with the NOI to allow for this opportunity at the discretion of the Department.

11.4 Study, Plan, and Report Requirements

11.4.1 End of Well (Class B Fluids) or End of Project (Class C Fluids) Reports

The permittee is required to submit an EOW or EOP Report by January 31st of each year following well or project completions. The permittee shall report the following for each drilling fluid system in the EOW or EOP Report:

a) Well or borehole designation, latitude and longitude of well/borehole entry and exist point if applicable (HDD); beginning and ending drill dates, and borehole diameter and associated depth (well or borehole) or length (HDD);

b) The base drilling fluid type;

c) A precise chemical inventory of all constituents added downhole, including all drilling fluid additives used to meet specific drilling requirements;

d) Any modifications to the drilling fluids system per the DFP, if applicable;

e) The total volumes of drilling fluid create and added downhole;

f) The estimated fluid loss at each site (if any);

g) Estimated total volumes of drilling fluids discharged to surface waters at each site location;

h) The maximum concentration of each constituent in the drilling fluid discharged to surface water;

i) The total volumes of drilling fluid discharged to surface waters;

j) Any control measures used to reduce or eliminate the release;

k) Any mitigation measures taken to eliminate or reduce adverse environmental impacts;

l) Any unusual observations reported to DEC;

m) Any supplemental information requested by DEC to be included during the project.

n) The use of surfactants, dispersants, and detergents per Permit Section 2.1.8;

o) The name and total amount of each chemical additive per 8.1.3, the results of the diesel oil analysis per 8.1.1.5, and metals analysis per 8.1.4.

For years where no wells or HDD drilling events occurred, the permittee must submit a statement in lieu of a report indicating such and whether future events are anticipated.

11.5 Environmental Monitoring Plan Requirements

11.5.1 Applicability

MODUs conducting oil and gas exploration and discharging Class B2 within 4,000 meters to 1,000 meters of Trading Bay SGR or the Redoubt Bay CHA must study the fate and effects of drilling fluids and/or cuttings discharges while operating in these areas. Environmental monitoring requirements are not applicable to discharges of Class B1 (e.g., top holes for oil and gas exploration wells drilled without the use of barite) or Class C drilling fluids from geotechnical surveys or HDD projects. Approval to discharge is contingent on meeting the requirements to obtain coverage under the Permit per Section 1.3.

11.5.2 Environmental Monitoring Plan Study

Operators of mobile exploratory facilities discharging drilling fluids and/or drill cuttings must submit a plan of study for environmental monitoring to DEC for review and comment with, or prior to, submission of an NOI.

11.5.3 Objectives

The objectives of the environmental monitoring must be to:

a) Monitor for drilling fluid discharge related impacts,

b) Determine statistically significant changes in sediment pollution concentrations and potential for sediment toxicity with time and distance from the discharge,

c) Monitor for discharge related impacts to the benthic community,

d) Assess whether any impacts warrant an adjustment of the monitoring program, and

e) Provide information for future permit reissuance.

11.5.4 Plan of Study

The monitoring must include, but not be limited to, relevant hydrographic, sediment hydrocarbon, and heavy metal data from surveys conducted before and up to at least one year after drilling operations cease. The study must consider the specific characteristics of the discharged Class B drilling fluids (e.g., parameters with monitoring requirements or limitations described in Sections 8.1.1 and 8.1.4) on the observed effects on sediment, water, and benthic communities if present. The monitoring plan must address:

a) The monitoring objectives,

b) Appropriate null and alternative test hypotheses,

c) A statistically valid sampling design,

d) All monitoring procedures and methods,

e) A quality assurance/quality (QA/QC) control program,

f) A detailed discussion of how data will be used to meet, test, and evaluate the monitoring objectives, and

g) A summary of the results of previous environmental monitoring as they apply to the proposed program plan.

11.5.5 Reporting Requirements.

The permittee must analyze the data and submit a report by January 31st following each year that an EMP sampling event occurred (i.e., Pre-drilling and Post-drilling Reports). The report must address the environmental monitoring objectives by using appropriate descriptive and analytical methods to test for and to describe any impacts of discharged drilling fluids on sediment pollutant concentrations, sediment quality, water quality, and the benthic community. The report must include all relevant QA/QC information, including but not limited to instrumentation, laboratory procedures, detection limits/precision requirements of the applied analyses, and sample collection methodology.

DEC will review the reports in accordance with the environmental monitoring objectives and evaluate it for compliance with the requirements of the Permit. If revisions to the report are required, the permittee must submit a revised report to DEC within two months of the request. The permittee will be required to correct, repeat, or expand environmental monitoring programs which have not fulfilled the requirements of the Permit.

For years where no EMP sampling events occurred, the permittee must submit a statement in lieu of a report indicating such and whether future events are anticipated.

11.5.6 Modification to Monitoring Program

The monitoring program may be modified if DEC determines that the modification is appropriate. The modified program may include changes in sampling stations, sampling times, and parameters.

11.5.7 Exemption

DEC may grant a written exemption to this requirement if the permittee can satisfactorily

demonstrate that information on the fate and effects of the discharge is available (e.g., EMP studies from previous wells at the location) or the discharge will not have significant impacts on the receiving environment in the area of discharge (e.g., sediment is significantly present at the site due to scour). A site specific exemption request may be submitted to DEC in writing for Department approval.

11.6 Drilling Fluid Plan Requirements.

11.6.1 Applicability

The permittee must develop and submit a DFP for Class B2 proposed to be discharged within 4,000 meters to 1,000 meters of Trading Bay SGR or the Redoubt Bay CHA or any Class C2 or C3 drilling fluid systems for HDD or geotechnical surveys. The applicant must submit the DFP for Department review and comment with, or prior to, submission of an NOI. Drilling fluids systems meeting Class B1 or C1 requirements do not require submittal of DFPs although DEC recommends permittees consider developing one as a contingency if additional chemical additives could be required during drilling and result in the fluid system to become reclassified and, thereby, trigger this requirement.

11.6.2 Implementation

The applicant must implement the written procedure in the DFP for the formulation and control of drilling fluid/chemical additive systems for each well or project. The DFP must specify the drilling fluid/chemical additive systems to be used. The plan must be implemented during drilling operations and a copy of the plan must be available on-site at the facility at all times. If applicable, the applicant must submit a copy of the completed DFP to DEC with the NOI.

11.6.3 Plan Requirements

At a minimum, the drilling fluid plan must include the following information:

11.6.3.1 Classification of drilling fluids proposed for discharge, the well or borehole designation, location, and any modified drilling fluid types as basic plan identification for each well or borehole to be drilled.

11.6.3.2 Specific to each well and drilling fluid type, provide a list including commercial product names, descriptions of the products, and the maximum proposed discharge concentrations for each product and chemical additive. Concentrations must be commonly stated in appropriate terms (e.g., lb/bbl, gal/bbl, % (wt), or % v/v (% volume oil per volume drilling fluid)). Each drilling fluid or additive system must be clearly labeled with respect to drilling fluid type (e.g., KCl/polymer drilling fluid, freshwater lignosulfonate drilling fluid). Components of the basic drilling fluid must be listed separately from specialty or contingency chemical additives which may be used.

11.6.3.3 For HDD projects, the DFP must include procedures that address observation for inadvertent releases at the shoreline, notification procedures to DEC, and methods to be implemented to stop the inadvertent release (e.g., additives to seal fractures, reduced operating pressure, etc.).

11.6.3.4 A record of the operator's determination of how discharge of drilling fluids and drill cuttings is expected to comply with the 30,000 ppm SPP toxicity limit for Class B2 drilling fluids or the SPP toxicity classification requirement of 500,000 for Class C2 or C3 drilling fluids. Operator's determination must be based upon but not limited to, the following criteria:

a) Estimate of worst-case cumulative discharge toxicity based on additive toxicity estimations or commercially calculated discharge toxicity estimations;

b) Estimations of discharge toxicity based on the use of mineral oil pills and subsequent discharge of residual mineral oil concentrations must be estimated separately from the proposed drilling fluid or additive system; and

c) Description of how overall toxicity is minimized, where possible.

11.6.3.5 A clearly stated procedure for determining whether or not a chemical additive not originally planned for or included in toxicity estimations may be used without resulting in a new drilling fluid classification, which could trigger additional limits or monitoring requirements (e.g., adding a third ingredient to a Class C1 Fluid or exceeding the SPP toxicity threshold for a Class B1 Fluid).

11.6.3.6 An outline of the drilling fluid planning process which must be consistent with other general permit requirements. Names and titles of personnel responsible for the drilling fluid planning process must be included in the drilling fluid plan.

11.7 Domestic Wastewater Characterization and Treatment Study Requirements

To support evaluation of appropriate treatment levels and limit development in the reissuance of the Permit, permittees are required to develop a sampling and analysis plan (SAP) of domestic wastewater discharges (treated black water and graywater), develop updated conceptual line diagrams depicting both graywater and treated black water systems for each potentially affected facility, and provide recommendations for DEC consideration. Recommendations may include, but are not limited to, modified limitations based on recent characterization data that would be protective of human health and the environment, proposed modifications to existing practices or upgrades to existing collection, treatment and disposals systems to meet existing limits based on the most recent version of 18 AAC 72. The SAP must be submitted to DEC for review during the second year of the term of the Permit. A characterization report with recommendations must be submitted with the next application for reissuance. This requirement is not applicable to facilities that combine all graywater with black water and meet effluent limits for domestic wastewater (Discharge 003).

12.0 OTHER LEGAL REQUIREMENTS

12.1 Endangered Species Act (ESA)

The ESA requires federal agencies to consult with NMFS and the U.S. Fish and Wildlife Service (USFWS) if their actions could beneficially or adversely affect any threatened or endangered species. As a state agency, DEC is not required to consult with these federal agencies regarding permitting actions. However, the Department has verbally discussed the Permit with the Services and is in the process of verifying listings of threatened and endangered species in the subject coverage area. There are four listed species and three species have critical habitat in Cook Inlet.

The following threatened and endangered species occur in Cook Inlet and are potentially affected by discharges covered under the Permit:

- Steller sea lion (*Eumetopias jubatus*): Endangered
- Beluga whale (*Delphinapterus leucas*): Endangered
- Northern sea otter (*Enhydra lutris kenyoni*): Threatened
- Steller's eider (*Polysticta stelleri*): Threatened

12.1.1 **Steller sea lion:** The NMFS listed the Steller sea lion as threatened on November 6, 1990 (55 FR 12645). On May 5, 1997, the NMFS issued a final rule that reclassified Steller sea lions into two distinct population segments (62 FR 24355). There is critical habitat for Steller sea lion within Cook Inlet at Cape Douglas, the Barren Islands, Port Chatham, and at the extreme southern end of Cook Inlet. There is additional critical habitat including rookeries, haulouts, and marine foraging areas for the western population stock in areas near Shelikof Strait, and areas

along the southern side of the Alaska Peninsula (MMS 2003).

12.1.2 **Beluga whale:** Beluga whales are divided into five stocks: Cook Inlet, Bristol Bay, eastern Bearing Sea, eastern Chukchi Sea, and Beaufort Sea (NMFS 2003). The Cook Inlet stock is classified as the most vulnerable, which led to listing the population as endangered under the ESA (73 FR 62919) on October 22, 2008 and followed by designating critical habitat in Cook Inlet on April 11, 2011 (76 FR 20180). The Cook Inlet population is the most isolated stock, spending the entire year in Cook Inlet and the majority of the time in the northern portion of Cook Inlet. The critical habitat areas are prioritized according to levels of sensitivity. The Permit coverage area excludes the highly sensitive habitat of the beluga whale. This critical beluga habitat is also excluded from oil and gas lease sales through DNR mitigation measures (DNR Cook Inlet BIF, 2009).

12.1.3 **Northern sea otter:** The USFWS issued a final rule listing the southwest Alaska distinct population segment of the northern sea otter as threatened under the ESA on August 9, 2005 (70 FR 46366). Designated habitat areas in Cook Inlet range along the west side from Shelikof Strait to Tuxedni Bay. These areas contains all the elements necessary for the conservation of the southwest Alaska northern sea otter population and thus is subject to special management considerations and protections to minimize the risk of oil and other hazardous-material spills from commercial shipping (74 FR 51988). The Permit coverage area overlaps with habitat areas from Chinitna Point to Tuxedni Bay.

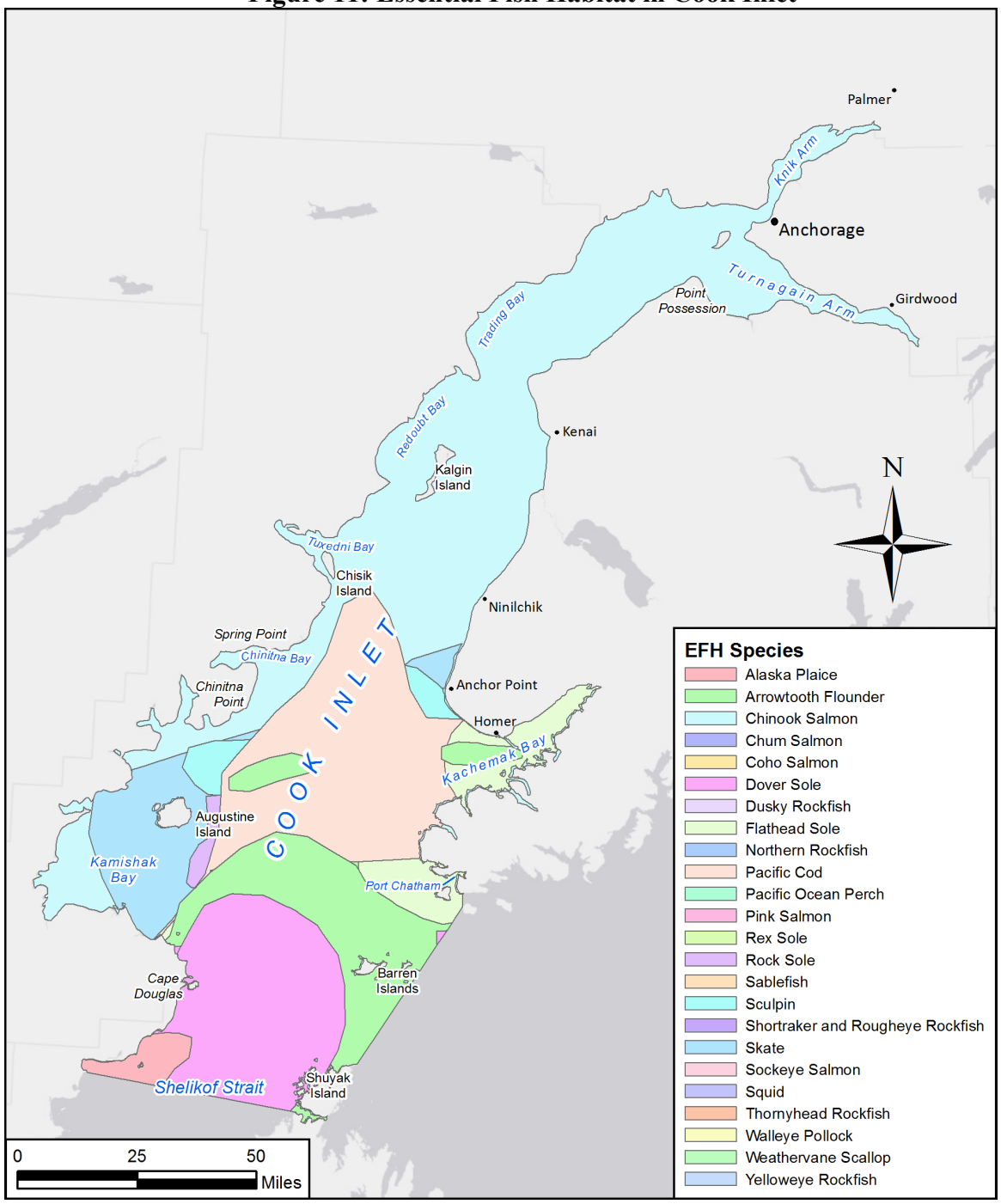
12.1.4 **Steller's eider:** The Alaskan breeding populations of Steller's eider were listed as threatened under the ESA on June 11, 1997 (62 FR 31748). Designated critical habitat for the Steller's eider includes five units located along the Bering Sea and north side of the Alaskan Peninsula. There is no critical habitat in Cook Inlet.

12.2 Essential Fish Habitat

Essential fish habitat (EFH) includes the waters and substrate (sediments, etc.) necessary for fish from commercially-fished species to spawn, breed, feed, or grow to maturity. The 1996 amendments to the Magnuson-Stevens Fishery Management and Conservation Act set forth a number of new mandates for NMFS, regional fishery management councils, and other federal agencies to identify and protect important marine and anadromous fish habitat.

Most marine waters surrounding the State of Alaska have been designated as essential fish habitat. Figure 11 provides a summary of the EFH species within the Permit coverage area.

Figure 11: Essential Fish Habitat in Cook Inlet



As can be surmised from Figure 11, EFH is prevalent in Cook Inlet much like most of Alaskan marine waters. The habitats of potential concern are typically the estuarine and near shore habitat of the Pacific salmon and herring spawning grounds. It is difficult to determine where facilities might locate during the life of a general permit. However, the prohibition of discharge within 4,000 meters of sensitive areas and in waters shallower than 10 meter serves to protect these near shore habitats. Because the discharges disperse rapidly within the deeper waters, activities associated with the Permit will not likely have an adversely affect on EFH.

12.3 Ocean Discharge Criteria Evaluation

During the issuance of the 2015 Exploration GP, DEC completed an Ocean Discharge Criteria Evaluation (ODCE) specific to state waters (territorial sea) to support permit issuance. The

ODCE was completed as part of a parallel permitting action with EPA that was issuing a similar general permit for federal waters concurrently and also developing an ODCE for federal waters. The ODCE also provided a good technical resource for the first reissuance of a Cook Inlet oil and gas general permit. However, DEC is not developing an ODCE for the Permit but is relying on this previous work supplemented with other more recent information and Alaska WQS.

CWA 403(a), Ocean Discharge Criteria, prohibits the issuance of a permit under CWA 402 for a discharge into the territorial sea, the water of the contiguous zone, or the oceans except in compliance with Section 403. Permits for discharges seaward of the baseline on the territorial seas must comply with the requirements of CWA 403, which include development of an ODCE.

The Permit requires compliance with Alaska WQS. Consistent with 40 CFR 125.122(b), adopted by reference at 18 AAC 83.010(C)(8), discharges in compliance with Alaska WQS shall be presumed not to cause unreasonable degradation of the marine environment. EPA made the connection between the similar protections provided by ODCE requirements and WQS when promulgating ocean discharge criteria rules in 1980, as stated, "the similarity between the objectives and requirements of [state WQS] and those of CWA 403 warrants a presumption that discharges in compliance with these [standards] also satisfy CWA 403." (Ocean Discharge Criteria, 45 Federal Register 65943.). As such, given the Permit requires compliance with Alaska WQS, unreasonable degradation to the marine environment is not expected and further analysis under 40 CFR 125.122 is not warranted for this permitting action.

12.4 Permit Expiration

The Permit will expire five years from the effective date.

13.0 REFERENCES

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Appendix A COOK INLET DESCRIPTION

A.1 General Cook Inlet Oceanographic Description

Most of the existing development and production facilities in Cook Inlet are in coastal waters in the area north of a line extending across Cook Inlet at the southern edge of Kalgin Island (Figure 1). Cook Inlet is unique and noted for large tides, strong currents, extensive mudflats, high turbidity, and fluctuations in salinity due to large glacial and freshwater inputs from surrounding drainages. The salinity of Cook Inlet is extremely complex. As such, three important factors influence the salinity within Cook Inlet: (1) a freshwater component responsible for introducing waters of low salinity; (2) a seawater component responsible for introducing waters of high salinity; and (3) a tidal component.

Tidal components are responsible for mixing freshwater inputs from rivers within Cook Inlet and from the Alaska Coastal Current (ACC) entering Cook Inlet at Kennedy Entrance (Okkonen et al. 2009). Cook Inlet is a 217-mile (350- kilometer) long, narrow, and semi-enclosed waterbody that has a free connection to the open ocean (MMS 2003; MMS 2000) with a general northeast-southwest orientation. It is divided naturally into the upper and lower regions by the East and West Forelands, where Cook Inlet is approximately 16 kilometers (10 miles) wide (SAIC 2001). The East and West Forelands constrict water flow and influence the movement of water. Cook Inlet, and its channels, coves, flats, and marshes, are a mixture of terrestrial sources from numerous river drainages and marine waters of Shelikof Strait and the Gulf of Alaska (MMS 2003). Cook Inlet varies in width from about 62 miles (100 kilometers) near the entrance to less than 12 miles (20 kilometers) at its head (MMS 2000). It has shoals towards its head where it separates into two narrow shallow arms (Knik and Turnagain). The Kachemak Bay is a large embayment on the east side. It has a deep channel and a spit that nearly bisects the bay at its midpoint. Kamishak Bay is a large embayment on the west side. It is relatively shallow and contains the Augustine Island volcano (Whitney, 2002).

The circulation of water in Cook Inlet is influenced by several factors, including the shape of the Inlet, bathymetry, freshwater input from rivers, the ACC, and tides. Temperature and salinity gradients exist between lower and central Cook Inlet, and between the east and west sides of the Inlet (Okkonen et al. 2009). Input of glacial silts and freshwater causes large fluctuations in sediment and salinity in the inlet. The water temperature in upper Cook Inlet varies with the seasons from 32 to 60 degrees Fahrenheit (°F) (0-15°C). Water temperatures of lower Cook Inlet, which is influenced by warmer, but more constant temperature waters entering from the Gulf of Alaska, range from 48 to 50°F (9-10°C) (KPB 2007). Higher maximum water temperatures in upper Cook Inlet may be influenced by relatively warmer water draining from lowland streams and rivers during the warmest parts of the year. Basins with 25 % or more of their area consisting of glaciers have the coldest water temperatures during the open-water season, mid-May to mid-October. Streams and rivers that drain lowlands have the warmest water temperatures (ODCE 2013).

Freshwater sources include glaciers and ice fields; glacial runoff and spring-fed streams; rivers; lakes; and wetlands. The majority of freshwater inputs are from rivers discharging into the upper region and along the west side of Cook Inlet. Glaciers cover 11 % of the land area of the Cook Inlet basin, storing massive amounts of water as ice, providing a large portion of the input to watersheds in the Cook Inlet area (ODCE 2013). The Cook Inlet area includes many watersheds, including 11 that drain major mountain ranges (BLM 2006). These include the Kenai Mountains on the Kenai Peninsula, the Chugach Mountains adjoining the Municipality of Anchorage, the Talkeetna Mountains in the Matanuska-Susitna area, the Alaska Range in the northwest, and the Chigmit, Neacola and Tordillo Mountains in the west (BLM 2006). Major rivers in the Matanuska-Susitna area include the Matanuska, Knik, Little Susitna, and Susitna rivers and their tributaries such as the Talkeetna and Yentna rivers; important lakes include Big, Nancy, Alexander, and Eklutna lakes (BLM 2006). In the Anchorage area, the primary rivers are Ship, Campbell, and Bird creeks, as well as the Eagle and Twentymile rivers. Larger rivers on the Kenai Peninsula include the Kenai, Ninilchik and Anchor

rivers; and among the larger lakes are Tustumena, Kenai, and Skilak lakes. Important rivers on the west side of Cook Inlet include the Drift, McArthur, Theodore, McNeil, and Kamishak rivers (BLM 2006). Cook Inlet receives large quantities of glacial sediment from the Knik, Matanuska, Susitna, Kenai, Beluga, McArthur, Drift, and other rivers. Intense tidal currents redistribute the sediment. Most of this sediment is deposited on the extensive tidal flats or is carried offshore through Shelikof Strait and eventually deposited in the Aleutian trench beyond Kodiak (KPB 2007; MMS 2003).

Mean salinities range from 29 to less than 31.5 Practical Salinity Units (PSU) from Tuxedni Bay and Anchor Point. The area near Tuxedni Bay and along the west side of Cook Inlet exhibits mean southward baroclinic flow (driven by gradients in pressure and density), whereas the area near Anchor Point and along the east side of Cook Inlet exhibits a weaker northward mean flow. The lowest salinities along this transect line occur in September. Mean temperatures along this same transect range from 6.5°C on the west side to 7°C on the east side, with maximum temperatures occurring in late August. Mean salinities range from 26 to 28 PSU between the Forelands, with salinities increasing from west to east. There is a mean southward baroclinic flow between the Forelands. The lowest salinities between the Forelands occur in mid-August, while the highest salinities occur in mid-February. Mean temperatures between the Forelands ranged from 5 to 5.5°C, with maximum temperatures occurring in mid-August. Tidal forces in Cook Inlet have a strong influence on salinity gradients as well. Mean surface salinities from Tuxedni Bay to Anchor Point are approximately 28 PSU with strong stratification during a neap tide, and 30 PSU with reduced stratification during a spring tide. Solar heating along with freshwater discharges increases in May and promotes increasing stratification through September (Okkonen et al 2009).

The fresher water from the upper Cook Inlet flows south along the west side and it eventually meets with the westward-moving ACC near Augustine Island. Seasonal changes in the freshwater inputs through the ACC and river discharge into Cook Inlet most likely control the non-tidal circulation in the lower region of Cook Inlet (Okkonen et al. 2009), since freshwater inputs promote intensification of geostrophic currents. The Alaskan Stream and a parallel current in the western Gulf of Alaska called the Kenai Current or the ACC influence the lower region of Cook Inlet (MMS 2003). The ACC flows along the inner shelf in the western Gulf of Alaska and enters Cook Inlet and Shelikof Strait (Schumacher and Reed 1980). The current is narrow (less than 30 kilometers [18.6 miles]) and high-speed (20–175 centimeters per second [cm/s] or 8–69 inches per second [in/s]) with flow that is driven by freshwater discharge and inner-shelf winds (MMS 2003). Peak velocities of 175 cm/s (69 in/s) occur in September through October (Johnson et al. 1988). The ACC transport volume ranges from 0.1–1.2 million cubic meters per second (m^3/s) or 106–317 million gallons per second, and varies seasonally in response to freshwater runoff fluctuations, regional winds, and atmospheric pressure gradients (ODCE 2013). The northern edge of the ACC generally follows the 100 meter isobath around the mouth of Cook Inlet. The southward flowing water along the western boundary is generally trapped by the ACC. Most of the freshwater flow out of Cook Inlet narrows to a few kilometers in width as it passes Cape Douglas at the southern end of Cook Inlet (Okkonen et al., 2009). Freshwater discharge measurements from the Susitna River in upper Cook Inlet show maximum discharge in May with seasonal variability associated with rainfall. Discharge decreases from June through August and begins to drastically reduce in September (Okkonen et al. 2009).

Convergence zones, known as tidal rips, are formed when the tidal and freshwater flows interact with the bathymetry (See Figure 15). These tidal rips are generally located above rapidly changing bathymetry. They often delineate strong gradients in water properties (e.g., temperature, salinity, and suspended sediments) as well as the speed of the current (Okkonen, 2004; Li et al., 2005). There are three main rips that are often evident in central Cook Inlet. They extend from the vicinity of the Forelands to beyond the southern tip of Kalgin Island. During the stages of the tidal cycle when the rips are strongest, they can accumulate debris, ice, and spilled oil along their axes. This material can become submerged and resurface downstream. The movement of material from one side of the rip to

the other is inhibited (Whitney, 2002). Figure 12 (USGS 2014) and Figure 13 (ODCE 2013) present the factors described above on Cook Inlet circulation flows. The mixing of incoming and outgoing tidewater, combined with freshwater inputs, are the main forces driving surface circulation (Figure 12; MMS 2003). The salinity of Cook Inlet varies significantly south to north, primarily resulting from more and larger streams discharging freshwater into upper Cook Inlet (e.g., Matanuska and Susitna rivers) and from the oceanic influence in lower Cook Inlet. Salinity values as low as 10 parts per thousand (ppt) have been measured at the surface in upper Cook Inlet (Smith 1993, cited in Foster et al. 2010) and as high as 32 ppt near the mouth (Smith 1993, cited in Foster et al. 2010; Okkonen et al. 2009). Hydrographic surveys showed that in central Cook Inlet, mean salinities increase from surface to bottom, from north to south, and from west to east, indicating a mean southward baroclinic (density-driven) flow along the west side of Cook Inlet in the upper part of the water column (Okkonen et al. 2009).

Cook Inlet current velocities vary widely, and generally depend on geography and tidal cycle. Johnson (2008) calculated tidal velocities using drifting buoys deployed northeast of Kalgin Island. Mean north-south tidal velocity was measured at 4.7 centimeters (cm)/second (s) flowing southward, while the mean west-east velocity was measured at 3 cm/s towards the west (Johnson 2008). Measured tidal velocities were measured up to 150 cm/s for both north-south and west-east flows. Johnson (2008) also calculated the kinetic energy (KE) from all drift buoy data. Figure 15 depicts KE contours south of the Forelands from measurements over 100 cm/s. The areas of high KE roughly correlate with the deep center channel in Cook Inlet. Musgrave and Statscewich (2006) utilized High Frequency (HF) radar systems near the mouth of the Kenai River in upper Cook Inlet to measure surface currents. A persistent southward current was observed near the northeast side of Kalgin Island at speeds up to 25 cm/s. Kinnetic Laboratories Inc. (2010) measured current velocities using an acoustic Doppler current profiler (ADCP) at Trading Bay near the West Forelands. Current velocities ranged from approximately 20 cm/s measured at the nearshore surface during a flood tide to 150 cm/s measured at the offshore surface during an ebb tide.

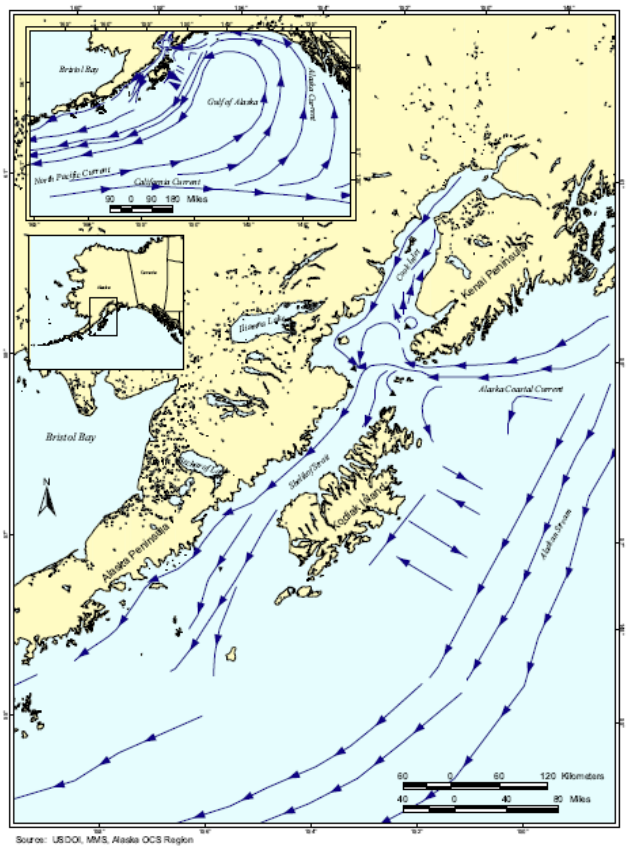
The lunar semidiurnal tide is the principal tidal influence in Cook Inlet, with two unequal high tides and two unequal low tides per tidal day (24 hours, 50 minutes). The mean diurnal tidal range varies from 13.7 ft (4.1 m) at the mouth of Cook Inlet to 29 feet (8.8 m) in upper Cook Inlet (KPB 2008). The resulting tidal currents create maximum surface currents that are generally 3.5 knots (5.5 km/h, 5 ft/s) in most of the inlet but over 6.5 knots at the foreland constriction during spring tides, with the associated tidal excursions sometimes exceeding 20 miles, and have been reported at up to 12 knots (20 ft/s, 22km/h) in the vicinity of Kalgin Island and Drift River (KPB 2007). Due to the large freshwater outflow from Upper Cook Inlet rivers south along the west side of the Inlet, the ebb tide excursions can be several miles faster. Strong tidal currents and Cook Inlet geometry produce considerable cross currents and turbulence within the water column. Tidal bores with current speeds up to 16.4 ft/s (9.7 knots or 5 m/s) have occurred in Turnagain Arm (Ezer et al. 2008). Current velocities are influenced by local shore configuration, bottom contour, and possibly wind effects in some shallow areas (MMS 2003). Due to the size, shape, and bathymetry of the Cook Inlet basin, a funneling effect and tidal resonance create some of the highest tidal amplitudes in the world. The difference contributes to the net southerly flow along the west side of Cook Inlet, especially when freshwater input is high.

The bathymetry of Cook Inlet is dynamic, with many deep areas and shoals. Two deep channels exist south of the Forelands, one between Kalgin Island and Harriet Point (approximately 240 feet [ft.] deep) and the other between Kalgin Island and the east side of Cook Inlet (approximately 450 ft.). These two channels extend southward in Cook Inlet and join in an area just west of Ninilchik (Gatto 1976). The bottom of Cook Inlet is extremely rugged with deep pockets and shallow shoals (KPB 2008). Upper Cook Inlet north of the Forelands is generally less than 120 ft (40 m) deep; the deepest portion is in Trading Bay, east of the mouth of the McArthur River. Two channels extend southward on either side of Kalgin Island, joining west of Cape Ninilchik. This channel gradually deepens to the south, to about 480 ft (120 m), and then widens to extend across the mouth of Cook Inlet from Cape Douglas to Cape

Elizabeth (KPB 2008). The 60-foot depth contour is generally located 2.5 to 3 miles (4 to 4.8 km) offshore along lower Cook Inlet, but falls within 0.7 miles (1.1 km) of shore for a length of about 3 miles (4.8 km) near Cape Starichkof (KPB 2008). The southeast coast of the Kenai Peninsula consists of a series of deep, glacially carved fjords (KPB 2008). Beach substrate may be sand, hard or soft mud, gravel, or cobble (Pentec Environmental 2005). The bottom currents in lower Cook Inlet are strong enough to prevent the deposition of sand-size and smaller particles (Sharma 1979; Hampton 1982). Regional sediments indicate sorting by present-day transporting currents (Hampton et al. 1981). Silts and muds are moved southward to outermost Cook Inlet and Shelikof Strait (Sharma and Burrell 1970; Carlson et al. 1977; Hampton 1982; Boehm 2001). Powered by the ACC, sediments of the Copper River drainage drift into lower Cook Inlet and Shelikof Strait where they eventually settle. MMS survey results indicate that about 10–20 % of the bottom sediments in the Cook Inlet area are from the Copper River (MMS 2000). Sediment accumulation rates in outer Cook Inlet and northern Shelikof Strait (approximately 100 miles southwest of Cook Inlet state waters) averaged 0.16 cm/year and ranged from 0.10 to 0.21 cm/year. Central and southern Shelikof Strait sediments averaged 0.68 cm/year and ranged from 0.46 to 0.94 cm/year (Rember and Trefry 2005). Copper River sediment in Cook Inlet is generally transported along the outer Kenai Peninsula into lower Cook Inlet, Kachemak Bay, and Shelikof Strait. Sediments transported down the west side of Cook Inlet are eventually deposited in the shallows of Kamishak Bay, deeper portions of outermost Cook Inlet, and Shelikof Strait (MMS 2000). Homer Spit is maintained by sediment transported from the north (KPB 2007).

Freshwater discharge in Cook Inlet remains high through the summer, though variable, and decreases from late September through November (Okkonen et al. 2009). While the ACC carries freshwater into lower Cook Inlet throughout the year, the freshwater signal varies with seasonal changes in coastal precipitation and wind mixing. The resulting ACC salinity minimum occurs in late September/early October; about a month later than the salinity minimum occurs in central Cook Inlet. The north-south salinity gradient is strongest in late summer/early fall when river discharges and glacial outflows are high. Although salinity within Cook Inlet may vary seasonally due to freshwater drainage volumes, the upper region is fresher than the lower region in all seasons (Okkonen et al. 2009). Thus, the seasonal evolution in freshwater transport is similar to the seasonal evolution of geostrophic currents. A typical seasonal river discharge profile somewhat resembles a step function (Okkonen et al. 2009). Following the winter discharge minimum, river discharge increases by more than an order of magnitude in May. In May, the estimated geostrophic currents are less than 0.2 meters per second (m/s) (Okkonen et al. 2009). The estimated geostrophic currents rise to over 1.0 m/s in the western Cook Inlet waters and 0.8 m/s in the ACC entering Cook Inlet (Okkonen et al. 2009). The strongest currents are in narrow bands in the fronts associated with the western Cook Inlet waters and the ACC. Since density gradients alter the phases of tidal currents, it can be inferred from the seasonal cycle of freshwater inputs to Cook Inlet (high inputs in summer and low inputs in winter) that density-driven currents will be weaker. Similarly, the phases of the tidal currents will be more uniform across Cook Inlet during winter than in summer (Okkonen 2005).

Critical ambient conditions considered in the CORMIX model are identified in the Permit application and evaluate the 10th percentile low current conditions and the 90th percentile high current conditions, 0.2 meters per second (m/s) and 2.3 m/s respectively. The receiving water density used to model is slightly stratified, from 1014 to 1016 kg/m3. This stratification condition differs from past mixing zone models and is based on data provided in recent reports (Kinnetic 2010).



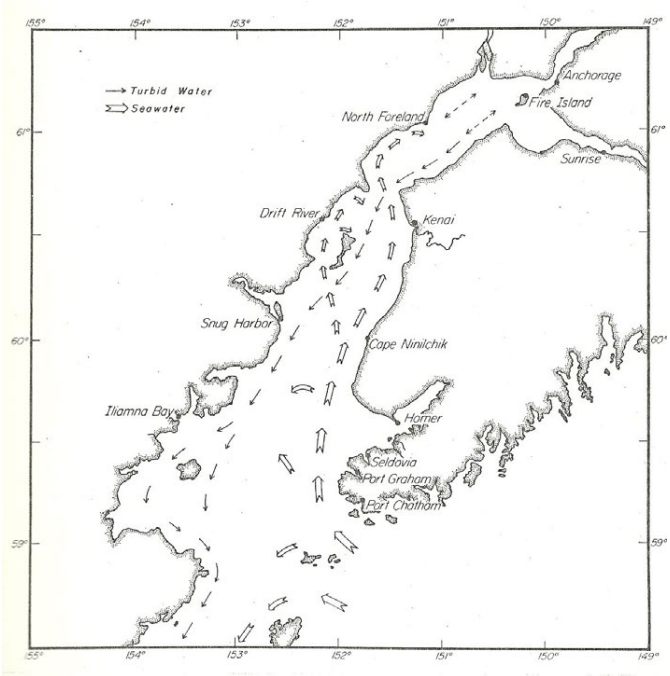


Figure 12: Sediment Deposition (MMS 2003)

Figure 13: Flow patterns in Lower and Upper Cook Inlet (Burbank 1974)

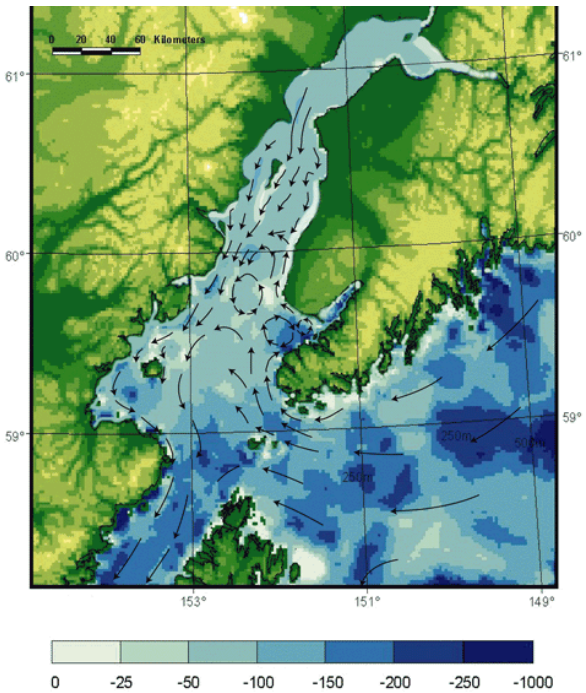


Figure 15: Cook Inlet Bathymetry and Currents

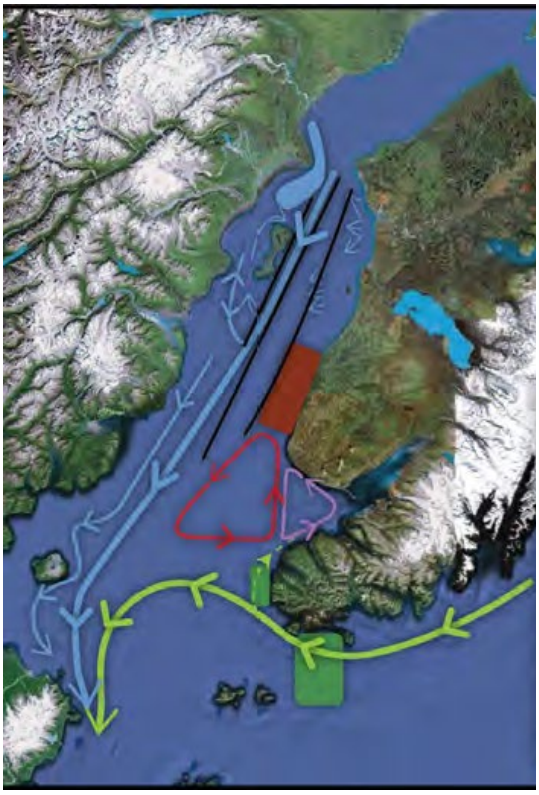


Figure 14: Cook Inlet Circulation Flow

A.2 New Cook Inlet Data for Mixing Zone Analysis

As discussed in Fact Sheet Section 6.2.1, the applicants submitting revised mixing zone evaluations for reissuance researched new information that was previously unavailable to refine past modeling efforts to result in better predictions of plume behavior. New information included current data collected by buoys deployed by the National Oceanographic and Atmospheric Administration (NOAA) at the Forelands, Middle Ground Shoal, and North Forelands over various short-term periods from 2005 to 2012. The NOAA current data provided confirmation of critical current speeds for the 10th and 90th percentile currents as well as the prevailing ebb and flood current directions. Typically, for rectangular mixing zones the 10th percentile current is used to determine plume width and the 90th percentile for the plume length in models. Previously, this led to long and narrow mixing zones that may not adequately explain plume behavior. By developing current roses, the applicants could evaluate ranges of current directions occurring around slack tide that led to conservative estimates of plume width. Because the main axis of the ebb and flood are not always 180 degrees apart as previously assumed, the authorized mixing zones have non-rectangular shapes that better define the actual boundaries of the acute and chronic mixing zones. Also, because there were multiple NOAA stations within the area of coverage, the applicants evaluated currents spatially and were able to adjust critical currents through interpolate or extrapolate for various facilities within the area of coverage. However, these adjustments were minor and the evaluation of the current data supports the generalized use of 0.3 meters per second (m/s) for the 10th percentile current and 2.3 m/s in most areas of coverage, similar to previous modeling determination.

During the Integrated Cook Inlet Monitoring and Assessment Program (ICIEMAP) in 2008 and 2009, receiving water and sediment samples were collected for the purpose of developing a Produced Water Study Report. Data collected included ambient hydrocarbons and metals of interest for mixing zone evaluations and reasonable potential analysis (RPA) during reissuance of the AKG315200- Oil and Gas Exploration, Development, and Production in State Waters in Cook Inlet (General Permit). In addition, data also included conductivity and temperature measurements at various depths (CTD casts) at 55 stations, with 38 of those collected via drogue near the discharge of produced water for the TBPF. The applicant used CTD casts from the 17 at large stations to conduct a conservative evaluation of critical density stratification conditions for modeling discharges over the general Cook Inlet coverage area. The 38 CTD casts and drogue track was used for specific evaluation of critical density stratification and current direction at TBPF. For the general area, a linear stratification from a medium shallow depth to the surface was used. For TBPF, a linear stratification from the bottom to the surface was used. These conserved critical stratification model inputs were also developed based on knowledge of the effluent densities and resulting impacts on plume behavior.

The ICIEMAP hydrocarbon and metals data included both water column and sediment samples. The water column samples did not result in detection of total aromatic hydrocarbons (TAH). While the focus here is on water column metals to support the mixing zone evaluation and RPA, the sediment metal data is relevant to the discharge of drilling fluids and drill cuttings containing barite and potential short-term zone of deposit resulting from the discharge. For evaluating mixing zones and determining appropriate dilution factors for the RPA, DEC procedures use an 85 percentile value of the ambient data. Except for mercury, the ICIEMAP data provided new information on background metals that have been used in the development of the General Permit. For mercury, the applicant used data collected by multiple other permittees discharging to the industrialized area in Nikiski area, near the Middle Ground Shoal Production Facility. This data was used due to the conservative nature of the location as being industrialized as well as the data quality. Table 52 provides a summary of the ambient data used in the General Permit.

Table 52: Receiving Water Ambient Concentrations

Parameter (Units)	Value	Published Date
Copper (micrograms per liter (µg/L))	0.926	2010*[1]
Mercury (µg/L)	0.0239	2014 [2]
Silver (µg/L)	0.00365	2010*[1]
Zinc (µg/L)	0.455	2010*[1]
TAH (milligrams per liter(mg/L)	0	2010*[1]
TAqH (mg/L)	0	2010*[1]

Notes:

* Includes samples collected with the Integrated Cook Inlet Environmental Monitoring Assessment Program (ICIEMAP, 2008)

Sources:

1) Produced Water Fate & Transport in Cook Inlet, 2008-2009 (Kinnetic Laboratories)

2) Kenai LNG ambient water sampling for AK0001155 permit renewal effort (Cook Inlet Environmental)

Figure 16 provides location of NOAA buoys and sample locations derived from the referenced studies used for modeling discharges from existing onshore production facilities and fixed platforms.

Figure 16: Cook Inlet Sample Stations

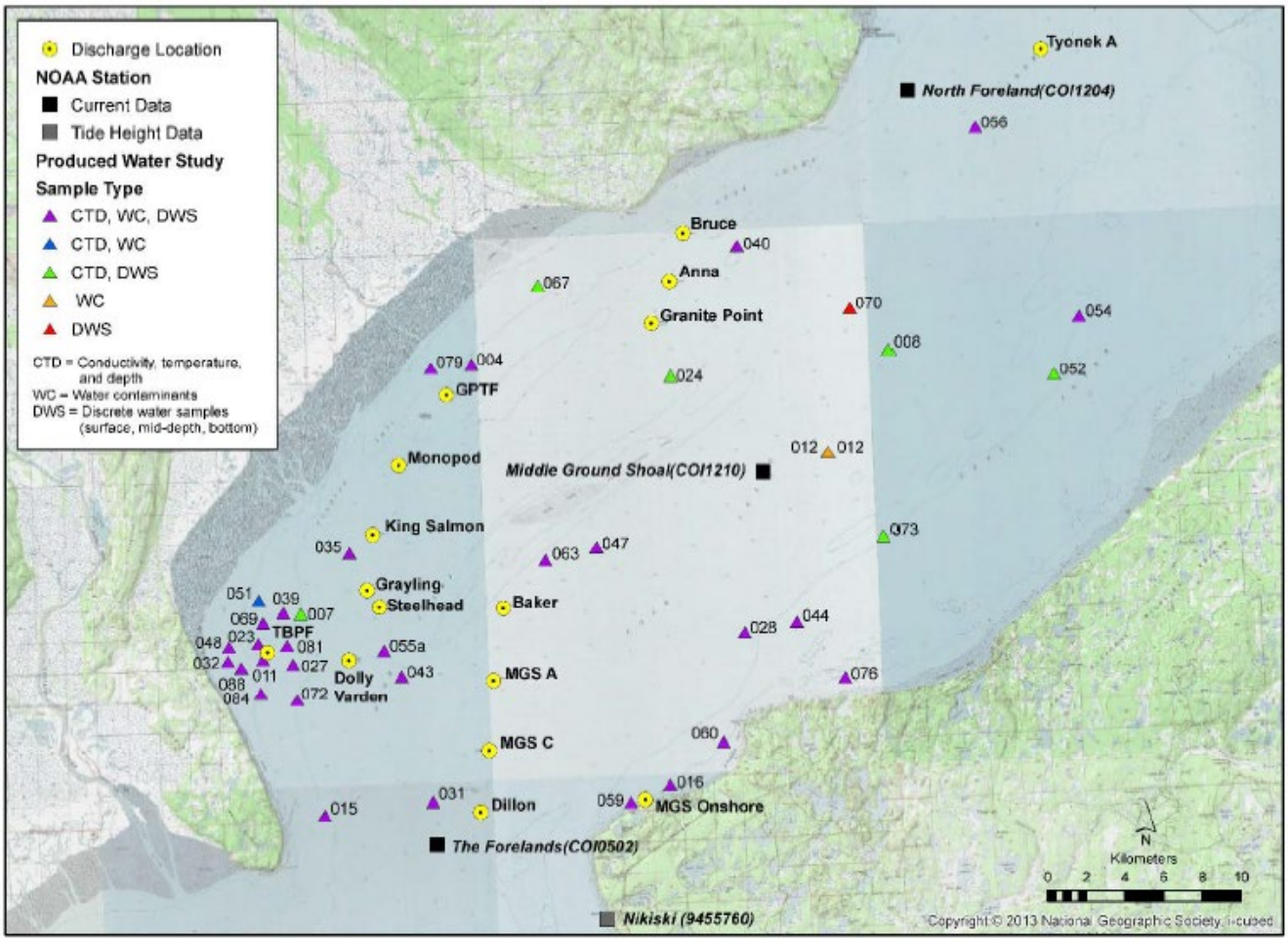
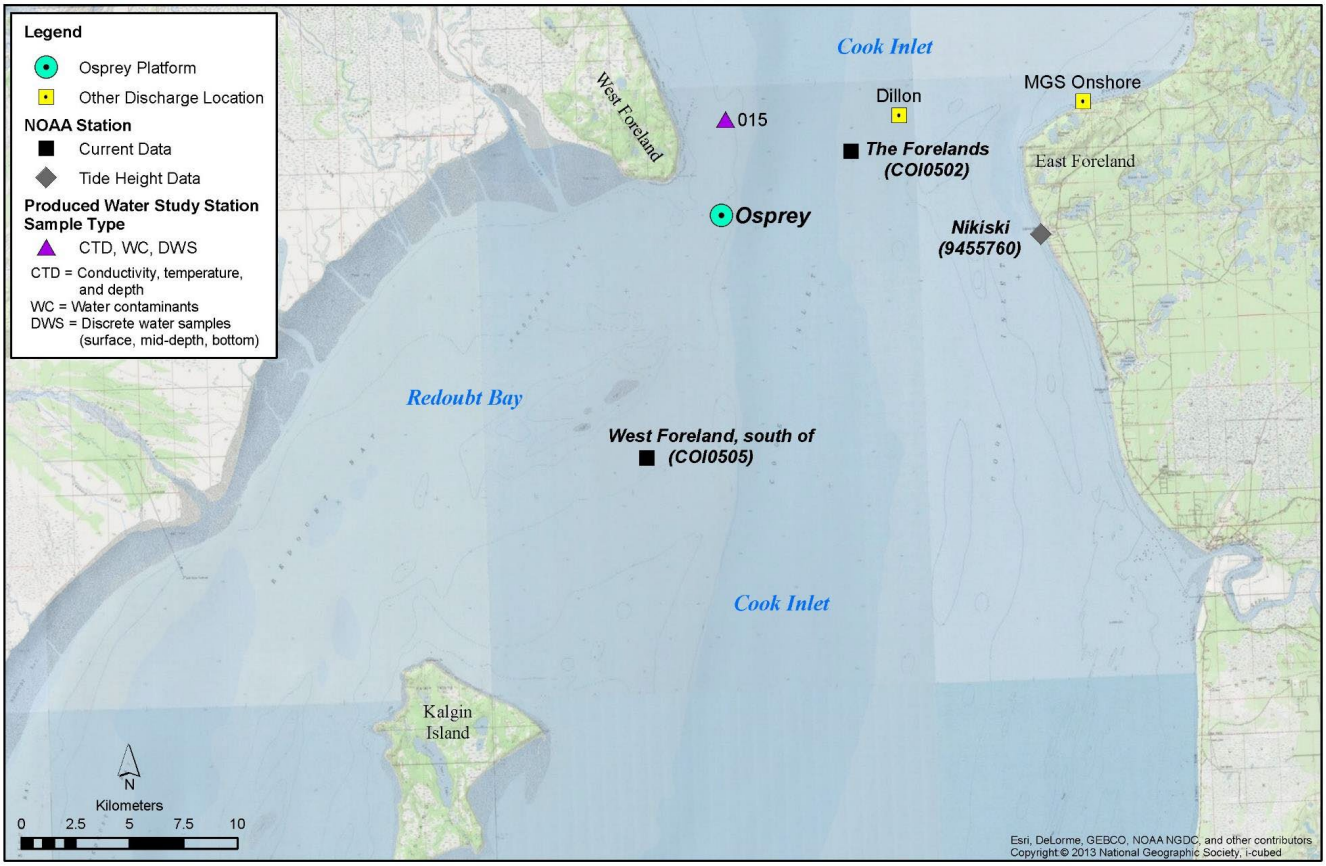


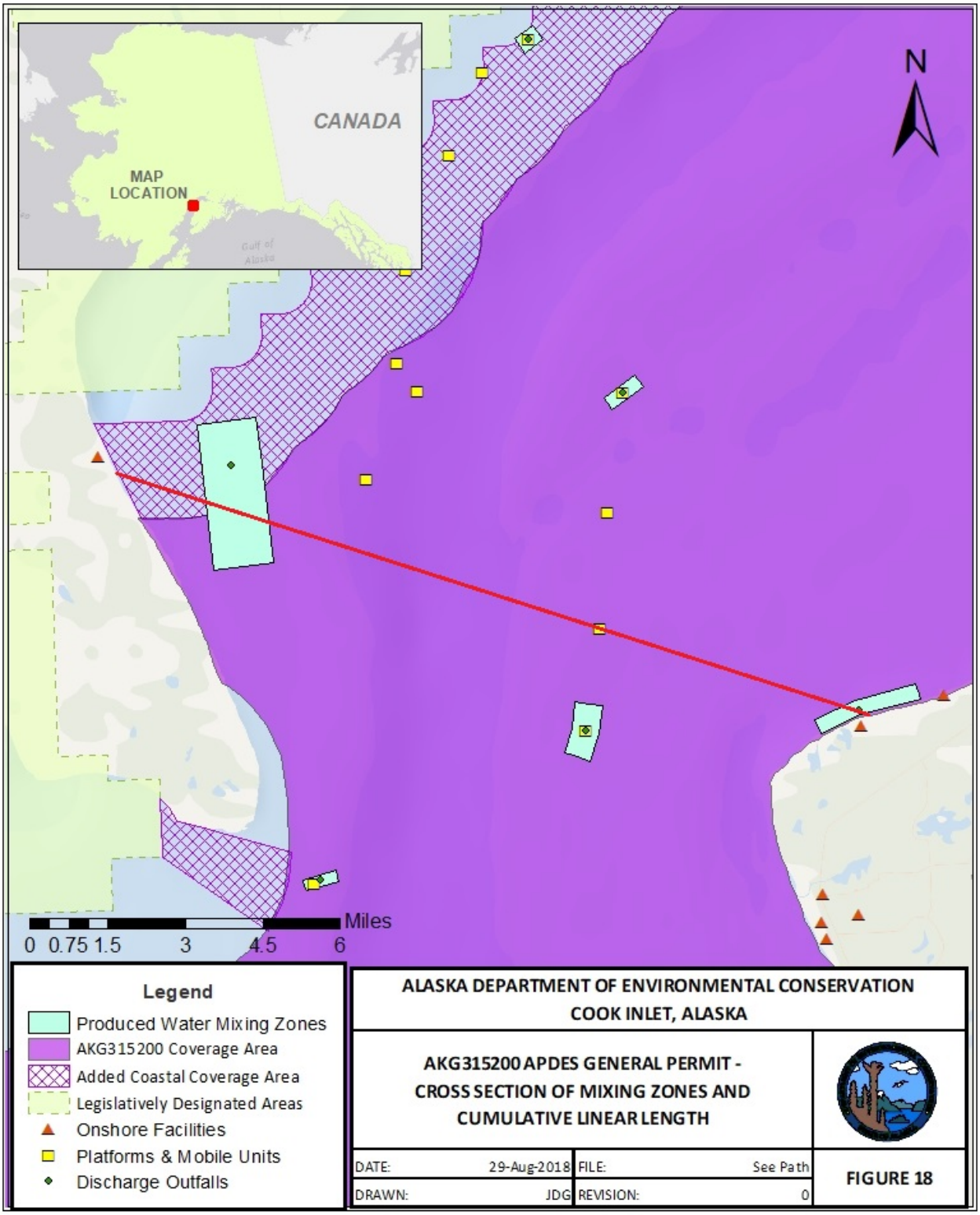
Figure 17 provides location of NOAA buoys and sample locations derived from the referenced studies used for modeling discharges from the Osprey Platform.

Figure 17: Forelands Sample Stations



To determine the cumulative length of chronic mixing zones for the worst-case transect across Cook Inlet, Figure 18 was developed using Graphical Interface Systems. For discussion, see Fact Sheet Section 6.2.4.

Figure 18: Cross Section of Mixing Zone and Cumulative Linear Length



The Department of Environmental Conservation (DEC) has compiled the computer representation from data or information sources that may not have been verified by the DEC. This general representation should not be re-used without verification of sources by an independent professional qualified to verify such data or information. DEC does not guarantee the accuracy, completeness or timelines of the information shown and shall not be liable for any loss or injury resulting from reference upon the representation. Sources: Alaska Department of Natural Resources, Land Records GIS, National Marine Fisheries Service,

Appendix B REASONABLE POTENTIAL ANALYSIS

This Appendix summarizes the reasonable potential analysis (RPA) process used by the Alaska Department of Environmental Conservation (Department or DEC) to determine and develop water quality-based effluent limits (WQBELs) for general permit AKG315200 – Oil and Gas Exploration, Development, and Production Facilities in State Waters in Cook Inlet (Permit).

Per Alaska Administrative Code (AAC) 18 AAC 83 - Alaska Pollutant Discharge Elimination System (APDES) Program requires limits in APDES permits to achieve water quality standards established under 33 USC 1313, including state narrative criteria for water quality. Alaska water quality standards are found in 18 AAC 70 – Water Quality Standards (WQS) and the *Alaska Water Quality Criteria Manual for Toxic and Other Deleterious Organic and Inorganic Substances, May 15, 2003 (Toxics Manual).*

Per 18 AAC 83.435(b), "Effluent limits in a permit must control all pollutants or pollutant parameters, either conventional, non-conventional, or toxic pollutants, that the department determines are or may be discharged at a level that will cause, have the reasonable potential to cause, or contribute to an excursion above any state water quality standard (i.e., criteria), including state narrative criteria for water quality."

DEC analyzes pollutant concentrations in the discharge to determine if it will cause, or contribute to, an exceedance of water quality criteria per the RPA procedures described in the *RPA and Water Quality-based Effluent Limits (WQBEL) Development Guide, June 30, 2014 (RPA&WQBEL Guide).* The *RPA&WQBEL Guide* is based partly on procedures in the Environmental Protection Agency (EPA) *Technical Support Document for Water Quality-Based Toxics Control, 1991 (TSD)* that were modified by the Department.

B.1 Review of Reasonable Potential Data for Produced Water

Produced water is the only discharge authorized under the Permit that requires an RPA based on numeric criteria; other discharges are adequately controlled using technology-based effluent limits (TBELs) or narrative water quality criteria. The previous general permit issued in 2007 by the Environmental Protection Agency (EPA), AKG315000 – Oil and Gas Exploration, Development, and Production Facilities in Cook Inlet (2007 GP) expired in 2012. All of the facilities that requested administrative extensions submitted applications in December 2011 that included produced water discharge data up to that time. These data were reviewed and analyzed by both DEC and permittees to help inform the permit renewal process. Specific items of review included a reasonable time-frame of useable data and confirming which discharges were being requested. The result of this initial review was a request to update the data to 2015 and research historic data for facilities that had not been discharging recently. For a couple of platforms that had not discharged during the last permit cycle and recent data was not available, additional data points were gathered from administrative records of previous permits and submitted Discharge Monitoring Reports (DMRs). DEC and permittees worked collaboratively to ensure each data point was assessed for appropriateness and reliability (in both record systems or with sufficient back-up documentation). The following describes actions taken to ensure decision were based on technically complete applications:

- January 2012 to July 2015: the time period selected for data review. Hilcorp required the majority of facilities in December 2011 and had operational control and access to DMR values and analytical reports for evaluation.
- Reviewed requested discharges in 2011 application and compared to actual and planned operation for each facility. A few facilities have changed operations and no longer require certain discharges and no longer request the authorization for those discharges.
- Evaluated facility piping for discharge velocities (for modeling mixing zone sizes) to be based on design capacity for all facilities

- Reviewed receiving water data found in produced water report, on NOAA site, from applications and other sources
- Collected, evaluated, analyzed data internally, and shared collated data with permittees. Permittees validated values, clarified where needed, and provided additional data for Baker and Dillon Platforms since they have not discharged during the last permit cycle.
- DEC and the permittee went through the RPA process separately and simultaneously to prove repeatability and transparency of process.

Characterization of the effluent was discussed in Fact Sheet Section 4.0 and results of the characterization of produced water is specifically addressed in Section 4.6. The purpose of the characterization process is to identify parameters of concern (POCs), such as parameters with technology-based effluent limits and water quality parameters that exceed criteria at the point of discharge. Those parameters that exceed acute or chronic criteria at the point of discharge are evaluated by considering the variability of the data and applying a factor to the highest observed concentrations to determine which parameter requires the most dilution to meet applicable water quality criteria. The parameters that require the most dilution to meet their respective acute and chronic criteria are typically considered driving parameters for determining the size of the acute and chronic mixing zones. Because DEC discretionarily authorizes less dilution than required, these driving parameters end up exceeding criteria at the boundary of the mixing zone, which triggers reasonable potential and forces development of a WQBEL for that parameter. If DEC constrains mixing zones significantly (e.g., impaired waterbody) and authorizes a dilution factor much lower than that required to meet the water quality criteria of the driving parameter, the second ranked POC could also have reasonable potential. However, this situation is not common.

For the chronic mixing zone, the characterization of the effluent for produced water at each facility demonstrated that, except for produced water from the Tyonek A Platform, the driving parameter for the chronic mixing zones for produced water is dominated by total aromatic hydrocarbons (TAH); the driving parameter for the Tyonek A chronic mixing zone is copper. TAH tends to be the driving parameter for the chronic mixing zones because of the high concentrations in produced water and the stringent numeric criteria for TAH. Hence, each facility except Tyonek A has reasonable potential for TAH to exceed, or contribute to an exceedance, of the chronic criteria for TAH. See Appendix C for WQBEL development.

For the acute mixing zone, three metals surfaced as potential driving parameters: copper, silver, and zinc. Based on the characterization data, the following provides a summary of which metals were ultimately determined to be the driving parameter for the acute mixing zone, and as a result, require a development of a WQBEL using the statistical variability of the characterization data for that parameter:

Copper	**Zinc**	**Silver**
TBPF	Baker	Dillon
GPTF	Bruce	MGS Onshore
Tyonek A		
Osprey		

Detailed calculations of the RPA for each facility is not provided in this appendix; only the RPA for the Trading Bay Production Facility (TBPF) is discussed in detail to serve as an example of the RPA process. The following sections provide the input parameters and RPA calculation equations for TBPF. A summary is provided for all facilities in Tables Table 53 and Table 54 in Section B5.

B.2 Mass Balance

For a discharge of a POC at the maximum expected concentration (MEC) (i.e., variability factor applied to the maximum observed concentration (MOC) into a marine receiving environment with a known ambient water concentration (AWC), the projected RWC is determined using a steady state model represented by the following mass balance equation:

$$(V_{MEC} + V_{AWC})RWC = V_{MEC}MEC + V_{AWC}AWC \qquad \text{(Equation B-1)}$$

where,

RWC = Receiving waterbody concentration downstream of the effluent discharge.

MEC = Maximum expected concentration.

AWC = Ambient waterbody concentration, taken as the 85th percentile of data or 15 percent of the chronic criteria if no ambient data is available.

V_{MEC} = Volume of the maximum expected effluent discharged into the control volume.

V_{AWC} = Volume of the ambient receiving water in the control volume.

Definition:

Dilution Factor (DF), $DF = \frac{(V_{MEC}+V_{AWC})}{V_{MEC}}$ (Equation B-2)

Upon separating variables in Equation B-1 and substituting Equation B-2 yields:

$$DF = \frac{(MEC-AWC)}{(RWC-AWC)} \qquad \text{(Equation B-3)}$$

Rearranging Equation B-3 to solve for RWC yields:

$$RWC = \frac{(MEC-AWC)}{DF} + AWC \qquad \text{(Equation B-4)}$$

For known MEC and AWC, Equation B-3 can be used to determine the required DF for a constituent by substituting water quality criteria for RWC. For cases where a DF and mixing zone have been authorized, Equation B-4 is used to calculate the RWC at the boundary of the mixing zone in the RPA.

B.3 Maximum Projected Effluent Concentration

To calculate the MEC, the Department uses the *RPA&WQBEL Guide* that modifies procedures in *TSD* section 3.3. Specifically, DEC uses a 95th confidence interval with a 99th percentile to determine a reasonable potential multiplier (RPM). These MEC can also be referred to as the maximum probable concentration during mixing zone determinations. In addition, DEC evaluates the distribution of the data set using EPA's *ProUCL Statistical Software Program, Version 4.1 (ProUCL)* rather than assuming a lognormal distribution as described in the *TSD* in calculating the coefficient of variation (CV). The possible statistical distributions include lognormal, normal, gamma, or non-parametric.

The RPM is calculated differently depending on the type of distribution, CV of the data, and the number of data points. When fewer than 10 data points are available, the *RPA&WQBEL Guide* assumes the CV = 0.6, a conservative estimate that assumes a relatively high variability.

The CV is defined as the ratio of the standard deviation of the data set to the mean.

$$CV = coefficient\ of\ variation = \frac{standard\ deviation}{mean},$$

For data sets with a Normal, Gamma, or Non-parametric (Kaplan-Meier) distribution:

$$CV = \frac{\hat{\sigma}}{\widehat{\mu_n}} \qquad \text{(Equation B-5)}$$

Where: $\hat{\mu_n}$ = estimated mean = $\Sigma[x_i] / k$, $1 \leq i \leq k$

σ^2 = estimated variance = $\Sigma[(x_i - \mu)^2] / (k - 1)$, $1 \leq i \leq k$
$\hat{\sigma}$ = estimated standard deviation = $(\sigma^2)^{1/2}$
k = number of samples

For data sets with a Lognormal or Log-ROS distribution:

$$CV = \left[exp\left(\hat{\sigma}_y^2\right) - 1\right]^{1/2} \quad \text{(Equation B-6)}$$

Where: $y_i = \ln(x_i)$ for $i = 1, 2, \ldots, k$
$\hat{\mu_y}$ = mean = $\Sigma(y_i) / k$
$\hat{\sigma_y}^2$ = variance = $\Sigma\,[(y_i - \hat{\mu_y})^2] / (k - 1)$
k = number of samples

The RPM is the ratio of the upper bound of the distribution at the 99th percentile to the percentile represented by the MOC at the 95% confidence level. The general equation is as follows:

$$RPM = \frac{C_{99}}{C_p} \quad \text{(Equation B-7)}$$

The specific equation depends on whether the data follows a lognormal distribution (Lognormal or Log-ROS) or normal distribution (Normal, Gamma, or Non-parametric). For normal distributions, Equation B-7 becomes:

$$RPM = \frac{\widehat{\mu_n} + Z_{99}\,\hat{\sigma}}{\widehat{\mu_n} + Zp_n\,\hat{\sigma}} \quad \text{(Equation B-8)}$$

For the lognormal distribution, Equation B-7 becomes:

$$RPM = \frac{\exp(Z_{99}\,\hat{\sigma}_y - 0.5\hat{\sigma}_y^2)}{\exp(Zp_n\,\hat{\sigma}_y - 0.5\hat{\sigma}_y^2)} \quad \text{(Equation C-9)}$$

In both Equations B-8 and B-9, the percentile represented by the MOC is:

$$p_n = (1 - confidence\ level)^{1/n} \quad \text{(Equation B-10)}$$

Where,

p_n = the percentile represented by the MOC
n = the number of samples
confidence level = 0.95 for this analysis

Although it is possible to have an RPM less than one with large data sets, the *RPA&WQBEL Guide* establishes the minimum RPM as one. The MEC is determined by multiplying the MOC by the RPM:

$$\text{MEC} = (\text{RPM}) \times (\text{MOC}) \quad \text{(Equation B-11)}$$

Either the acute or chronic projected RWC at the boundary of an authorized mixing can be determined using the MEC calculated in Equation B-11 in Equation B-4.The projected RWC at the boundary of the mixing zones are then calculated as follows:

$$\text{RWC}_{\text{a,c}} = \frac{\text{MEC} - \text{AWC}}{\text{DF}_{\text{a,c}}} + \text{AWC} \quad \text{(Equation B-12)}$$

Where:

$RWC_{a,c}$ = receiving water concentration at the boundary of the acute or chronic mixing zone, and

$DF_{a,c}$ = the authorized acute or chronic dilution factor.

If the RWC at either the acute or chronic mixing zone boundary is found to exceed the respective criteria for the POC, then reasonable potential exists for that parameter and a WQBEL must be developed for that parameter.

B.4 Example Calculations for TAH as a Chronic WQBEL

The mixing zone analysis identified TAH as the driving parameter for the chronic mixing zone at TBPF and the Department authorizes an acute mixing zone with a DF_c of 1,335. TAH is found to have reasonable potential because the required dilution factor needed to meet TAH chronic water quality criteria is 1,336 and Department authorizes slightly less dilution than required to meet water quality criteria at the boundary. The following calculations demonstrate how TAH resulted in reasonable potential:

Number of effluent data (n) = 43
MOC = 11.8 mg/L

The Department calculated the CV based on the mean and standard deviation of raw data values obtained from EPA's ProUCL-Version 4.1 Statistical Analysis Program as shown below:

Mean of Raw Data ($\hat{\mu}_n$) = 8.211, and
Standard Deviation of Raw Data ($\hat{\sigma}$) = 1.725
CV = 0.21

A normal distribution applies to the data so equation B-8 applies to the RPM,

For a data set containing 43 TAH samples:

Percentile represented by MOC $(p_n) = p_{43} = (1 - 0.95)^{1/43}$

$P_{43} = 0.9327$ and $Zp_{43} = 1.496$

By inputting values into Equation B-8 results in an RPM = 1.133

The MEC is then calculated by B-11 as the product of the RPM x MOC

MEC = (1.133)(11.8 mg/L) = 13.37mg/L

The chronic receiving water concentration is then calculated based on the following input parameters into B-12:

AWC = 0 mg/L (Ambient samples analyzed were below detection)

DF_c = 1,335

Resulting in:

$$RWC_c = \frac{13.37\ mg/L_e - 0}{1{,}335} + 0\ mg/L = 0.0101\ mg/L$$

In order to determine if reasonable potential exists for the discharge to violate water quality criteria, the projected concentrations at the boundary of the chronic the mixing zone is compared to the water quality criteria. As shown in the comparison below, TAH has reasonable potential to violate applicable water quality criteria at the boundary of the chronic mixing zone.

Chronic: 0.0101 mg/L > 0.0100 mg/L (chronic criteria) **YES**, there is a reasonable potential.

Since there is a reasonable potential for the effluent to cause, or contribute to, an exceedance of chronic water quality criteria for protection of aquatic life, a WQBEL for TAH is required. See Appendix C for development of this limit.

B.5 Example Calculations for Copper as an Acute WQBEL

The mixing zone analysis identified copper as the driving parameter for the acute mixing zone at TBPF and the Department authorizes an acute mixing zone with a DF_a of 4.5, which is less than the dilution factor required to meet acute water quality criteria for copper (4.7). The calculations demonstrating reasonable potential for copper are summarized below:

Number of effluent data (n) = 55
MOC = 19.9 µg/L Total Recoverable (Conversion factor for dissolved is 0.83)

The Department calculated the CV based on the mean and standard deviation of raw data values obtained from EPA's ProUCL-Version 4.1 Statistical Analysis Program as shown below:

Mean of Raw Data ($\hat{\mu}_n$) = 5.331, and
Standard Deviation of Raw Data ($\hat{\sigma}$) = 2.678
CV = 0.502

A normal distribution applies to the data so equation B-8 applies to the RPM

For a data set containing 55 copper samples:

Percentile represented by MOC $(p_n) = p_{55} = (1 - 0.95)^{1/55}$

$P_{55} = 0.9470$ and $Zp_{55} = 1.616$

By inputting values into Equation B-8 results in an RPM = 1.197

The MEC is then calculated by B-11 as the product of the RPM x MOC

MEC = (1.197)(19.9 mg/L) = 23.82 µg/L

The chronic receiving water concentration is then calculated based on the following input parameters into B-12:

AWC = 0.926 µg/L (Represents the 85 percentile of ambient data)

$DF_c = 4.5$

Resulting in:

$$RWC_a = \frac{23.82\ ug/L\ \ -0.926\ ug/L}{4.5} + 0.926\ ug/L = 6.01\ \mu g/L$$

In order to determine if reasonable potential exists for the discharge to violate ambient criteria, the projected concentrations of copper at the boundary of the acute the mixing zone is compared to the acute water quality criteria. As shown in the comparison below, copper has reasonable potential to violate applicable water quality criteria at the boundary of the chronic mixing zone.

Acute: 6.01 µg/L > 5.78 µg/L (acute criteria) **YES**, there is a reasonable

Since there is a reasonable potential for the effluent to cause, or contribute to, an exceedance of chronic water quality criteria for protection of aquatic life, a WQBEL for copper is required. See Appendix C for development of this limit.

B.5 Reasonable Potential Analysis Summary

An evaluation of each POCs identified in Fact Sheet Section 4.6.4 for produced water was conducted using the acute and chronic dilution factors authorized in the mixing zones and the respective acute and chronic water quality criteria for the parameter. Of the chronic parameters, TAH was predominantly an obvious driving parameter for all facilities except Tyonek A, which had copper as an obvious driving parameter not only for the chronic mixing zone, but also the acute mixing zone. For the acute driving parameters, all but the Dillon could be predetermined based on characterization to be either copper at four facilities, silver (Ag) one facility, and zinc (Zn) at two facilities. Dillon (the eighth facility) required an RPA to determine whether silver or zinc was the driving parameter and required a WQBEL. Table 53 provides a summary of the input parameters, and results for determining reasonable

potential (RP) at the boundary of the chronic mixing zone.

Table 53: Summary of Chronic RPA

Facility	POC	Units	n	DF_c	MOC	AWC	mean	σ	CV	RPM	MEC	RWC	WQC	RP Y/N
TBPF [1]	TAH	mg/L	43	1335	11.8	--	8.21	1.73	0.210	1.133	13.37	0.0101	.01	**Y**
MGS Onshore [1]	TAH	mg/L	41	2180	18.93	--	13.41	3.32	0.247	1.154	21.85	0.0102	.01	**Y**
GPTF [2]	TAH	mg/L	67	2175	19.52	--	11.74	3.39	0.289	1.116	21.79	0.0102	.01	**Y**
Baker [1]	TAH	mg/L	45	3390	28.22	--	12.43	2.87	0.231	1.202	33.92	0.0101	.01	**Y**
Bruce [1]	TAH	mg/L	42	3395	28.99	--	17.30	5.12	0.296	1.173	34.01	0.0102	.01	**Y**
Dillon [1]	TAH	mg/L	45	3390	28.22	--	12.43	2.87	0.231	1.202	33.92	0.0101	.01	**Y**
Tyonek A [2]	Cu	µg/L	50	280	272	0.926	16.62	42.0	2.524	2.908	791	3.75	3.7	**Y**
Osprey [2]	TAH	mg/L	12	800	6.93	--	5.945	0.68	0.114	1.163	8.06	0.0107	.01	**Y**

Notes:
1. Normal Distribution Applies.
2. Lognormal Distribution Applies.

Table 54 provides a summary of the input parameters, and results for determining reasonable potential at the boundary of the chronic mixing zone.

Table 54: Summary of Acute RPA

Facility	POC	Units	n	DF_a	MOC	AWC	mean	σ	CV	RPM	MEC	RWC	WQC	RP Y/N
TBPF [1]	Cu	µg/L	55	4.5	19.9	0.926	5.331	2.678	0.502	1.197	23.82	6.01	5.78	**Y**
MGS [1] Onshore	Ag	µg/L	14	21.5	28.1	0.00365	8.968	8.915	0.994	1.778	49.96	2.33	2.30	**Y**
GPTF [2]	Cu	µg/L	35	11.5	40.9	0.926	7.841	8.817	1.124	1.41	57.67	5.86	5.78	**Y**
Baker [2]	Zn	µg/L	51	134	8000	0.455	2127	1467	0.690	1.593	12744	95.56	95.1	**Y**
Bruce [1]	Zn	µg/L	15	268	8260	0.455	2201	2058	0.935	3.069	25345	95.22	95.1	**Y**
Dillon [1]	Ag	µg/L	14	21.5	28.1	0.00365	9.54	8.63	0.905	1.78	50.02	2.33	2.30	**Y**
Dillon [1]	Zn	µg/L	45	21.5	1400	0.455	665.7	310.7	0.467	1.22	1708	79.88	95.1	N
Tyonek A[2]	Cu	µg/L	50	160	272	0.926	16.62	41.95	2.524	2.908	791.0	5.86	5.78	**Y**
Osprey[3]	Cu	µg/L	8	40	71.3	0.926	--	--	0.6	2.8	199.6	5.89	5.78	**Y**

Notes:
1. Normal Distribution Applies.
2. Lognormal Distribution Applies.
3. Because there are less than 10 data points, the distribution is assumed to be lognormal, the CV defaults to 0.6 so the mean and standard deviation are needed.

Appendix C BASIS OF LIMITS

The Alaska Department of Environmental Conservation (Department or DEC) prohibits the discharge of pollutants to waters of the United States (U.S.) per Alaska Administrative Code (AAC) 18 AAC 83.015 unless first obtaining a permit issued by the Alaska Pollutant Discharge Elimination System (APDES) Program that meets the purposes of Alaska Statutes (AS) 46.03 and is in accordance with Clean Water Act (CWA) Section 402 (CWA 402). Per these statutory and regulatory requirements, general permit AKG315200 – Oil and Gas Exploration, Development, and Production in Cook Inlet in State Waters (Permit) includes effluent limitations that require the discharger to (1) meet standards reflecting levels of technological capability, (2) comply with 18 AAC 70 – Alaska Water Quality Standards (WQS), (3) and comply with other state requirements that may be more stringent.

The CWA requires that the limits for a particular parameter be the more stringent of either technology-based effluent limits (TBEL) or water quality-based effluent limits (WQBEL). TBELs are set via rule makings by the Environmental Protection Agency (EPA) in the form of Effluent Limitation Guidelines (ELGs) that correspond to the level of treatment that is achievable using available technology. In situations where ELGs have not been developed or have not considered specific discharges or pollutants, a regulatory agency can develop TBELs using best professional judgment (BPJ) on a case-by-case basis. A WQBEL is designed to ensure that WQS are maintained and the waterbody as a whole is protected. WQBELs may be more stringent than TBELs. In cases where both TBELs and WQBELs have been generated, the more stringent of the two limits will be selected as the final permit limit. Per the *Technical Support Document for Water Quality-based Toxics Control* (TSD), once a specific type of limit has been decided, the permitting authority has some discretion in specific permit limit derivation procedures. When using this discretion, the procedure should be fully enforceable, account for effluent variability, consider available receiving water dilution, protect against acute and chronic impacts, account for compliance monitoring frequencies, and protect wasteload allocation (WLA) and ultimately WQS. An example of implementing such discretion is retaining limits from the existing Permit that are found to be more stringent than those developed for the Permit using typical procedures but are attainable based on review of historic effluent performance data.

C.1 TECHNOLOGY BASED EFFLUENT LIMITS

C.1.1 TBELs Based on Effluent Limitation Guidelines

EPA has promulgated national ELGs for the Oil and Gas Extraction Point Source Category at 40 CFR 435 Subparts A (Offshore Subcategory) and D (Coastal Subcategory). DEC adopted the ELGs by reference at 18 AAC 83.010(g)(3). These subparts specify Best Available Technology Economically Achievable (BAT); Best Conventional Pollutant Control Technology (BCT); and Best Practicable Control Technology Currently Available (BPT), and new source performance standards (NSPS) for the Offshore and Coastal Subcategories of the Oil and Gas Point Source Category. The NSPS do not apply to new exploratory facilities because exploration is conducted at a particular site for a short duration and generally consists of drilling only one to three wells. In general, exploratory facilities differ from development and production new sources in that they do not have high volume discharges, and they do not discharge produced water.

The ELGs for the Coastal Subcategory were promulgated in 1996. During development of the ELGs, information from the discharging platforms Anna, Baker, Bruce, Dillon, and Tyonek A along with onshore production facilities Trading Bay Production Facility (TBPF), Middle Ground Shoal (MGS) Onshore, and Granite Point Tank Farm (GPTF) were included in the evaluation of applicable ELGs. The evaluation led to an understanding that the Cook Inlet oil and gas region is unique when compared to other coastal locations in the U.S. for discharging drilling fluids and drill cuttings and produced water. Furthermore, because the produced water treatment systems were included in the evaluation, the existing facilities listed comply with model technology and meet the definition of highest statutory and regulatory requirements for ELGs. However, the Osprey Platform that is seeking first time

authorization to discharge produced water under the ELGs, must ensure that the treatment of produced water meets the model technology based improved gas flotation prior to obtaining coverage under the Permit. The following sections discuss the applicable ELGs Drilling Fluids and Drill Cuttings from oil and gas facilities (Discharge 001); Deck Drainage (Discharge 002); Domestic Wastewater as defined by 18 AAC 72 but title sanitary waste in the ELGS (Discharge 003); Graywater as defined by 18 AAC 72 but title domestic waste in the ELGS (Discharge 004); Produced Water (Discharge 015), and Well Treatment (Discharge 016), Workover (Discharge 017), and Completion Fluids (Discharge 018).

C.1.1.1 ELGs for Drilling Fluids and Drill Cuttings (001)

The Permit only authorizes the discharge of water-based drilling fluids (WBFs). WBFs can be discharged with cuttings in either the coastal waters or the territorial sea under the Permit. Operators may choose to use non-aqueous fluids (NAF), which are oil or synthetic-based drilling fluid (OBF or SBF). Although NAF cannot be discharged, the cuttings coated with residual NAF can be discharged to the territorial seas after the NAF has been separated. The ELGs address to what quantity and quality of NAF is allowed to be adhered to cuttings discharged. In addition, the discharge of cuttings with NAF adhered to the surface is not allowed in coastal waters. Hence, 40 CFR 435 Subparts A (Offshore Subcategory) applies to NAF. A detailed discussion of oil- and synthetic-based drilling fluids can be found in the *Environmental Assessment of Final Effluent Limitations Guidelines and Standards for Synthetic-Based Drilling Fluids and other Non-aqueous Drilling Fluids in the Oil and Gas Extraction Point Source Category* (EPA 2000).

DEC is also including drilling fluids and drill cuttings from non-oil and gas drilling applications in the Permit. In order to distinguish between oil and gas and non-oil and gas regulatory requirements, DEC developed classes of drilling fluids where Class B Fluids are oil and gas applicable to the ELGs and Class C Fluids are non-oil and gas discharged to marine waters that are not applicable to the ELGs. Non-oil and gas drilling fluids are used in geotechnical surveys and horizontal directional drilling (HDD) projects and are not subject to the oil and gas ELGs. DEC further developed tiers under each classification based on the relative complexity and/or toxicity for the purpose of imposing varying levels of regulatory protection to the environment. The tiered system allows minimally toxic drilling fluids to be used in near-shore environments in a manner that is protective. More information can be found in Fact Sheet Sections 4.1.4 and 11.5.1.

C.1.1.1.1 ELGs for WBF per 40 CFR 435 Subpart A and Subpart D

The Permit includes the following limits and prohibitions:

- No discharge of free oil (Static Sheen Test),
- No discharge of diesel oil,
- Cadmium and mercury limits on stock barite, and
- Toxicity limit of 3 percent (%) by volume.

The ELGs limit the discharge of organic contaminants by prohibiting the discharge of free oil as determined by the Static Sheen Test (EPA Method 1617), prohibiting the discharge of diesel, and by restricting the use of mineral oil in drilling fluids. If drilling fluids and drill cuttings fail the Static Sheen Test, the permittee must collect a sample and analyze it for diesel. To determine the presence of diesel oil, a gas chromatograph (GC) analysis described in "Analysis of Diesel Oil in Drilling Fluids and Drill Cuttings" (CENTEC, 1985).

Permittees must also evaluate toxicity using a 96-hour test for a 50 % lethal concentration (LC_{50}) on the suspended particulate phase (SPP) using the *Leptocheirus plumulosus* species (EPA Method 1619). Test procedures are found in 40 CFR 435, Subpart A, Appendix 2. The permittee must collect a sample monthly and at the end of drilling a well (EOW) where no mineral oil has been used for the test. The ELG limits the SPP LC_{50} to 30,000 parts per million (3 %) by volume.

Stock barite, which is commonly added as a weighting agent to drilling fluids, is the main source of heavy metals in drilling fluid discharges. The TBELs for cadmium and mercury, 3.0 milligram per kilogram (mg/kg) and 1.0 mg/kg respectively, serve as surrogate parameters for other metals contained in the barite. Permittees are required to report cadmium and mercury concentrations measured in the stock barite before it is added to the drilling fluids, using EPA Method 245.5 or 7471 for mercury and EPA Method 200.7 for cadmium.

C.1.1.1.2ELGs for NAF per 40 CFR 435 Subpart A

The ELGs prohibit discharges of oil-based drilling fluids, inverse emulsion drilling fluids, oil-contaminated drilling fluids, and drilling fluids to which mineral oil has been added. These prohibitions are consistent with the prohibition of free oil and to ensure compliance with the toxicity limits. Similar to WBF, compliance is determined by the Static Sheen Test on cuttings. Exceptions to these prohibitions may be granted for drilling fluids to which a mineral oil pill has been added (See Fact Sheet Section 8.1.1.16). A pill is defined as a discrete amount of mineral oil circulated through a well to free stuck pipe.

The Permit also prohibits all discharges of NAF, except NAF adhered to drill cuttings after separating fluids from the cuttings for reuse. The discharge of NAF coated drill cuttings apply to the territorial seas but not the coastal zone. The ELGs include mass ratio limits of NAF adhered to cuttings based on the type of oil.

While the ELGs do not specify the types of NAF, the ELGs include limits for sediment toxicity and biodegradation, which encourage operators to use fluids that are less toxic having a higher biodegradation rate (DEC 2015).

C.1.1.1.3 ELGs for NAF Adhered to Drill Cuttings per 40 CFR 435 Subpart A

Cuttings maybe discharged to the territorial sea under the Permit through an outfall or shunt line. This discharge may contain small amounts of drilling fluids that remain adhered to the surface of the cuttings after the solids separation process. The main source of pollutants in drill cuttings are associated with the drilling fluids that adhere to the rock particles (EPA 2000). The ELGs for no free oil (Static Sheen Test), no diesel, SPP, and mercury and cadmium in barite also apply to the discharge of cuttings with NAF adhered to the surface.

The ELGs include limits for sediment toxicity and biodegradation. Rather than specifying types of synthetic-based fluids, permittees must use less toxic fluids that biodegrade quickly in order to meet these limits. Typically, the use of NAF reduces the necessary borehole size that is drilled. This reduces the volume of cuttings discharged and limits on toxicity and biodegradation help lessen potential adverse environmental impacts. Currently, there are no fixed platforms operating in the territorial sea nor are there currently any active exploration projects planned in the territorial sea in Cook Inlet.

The Permit contains limits for NAF at three points:

- The combined fluid components are limited for formation oil contamination as measured using gas chromatography/mass spectrometry (GC/MS),
- Drilling fluids that adhere to drill cuttings are limited for sediment toxicity (96-hour) and by the amount of residual NAF and formation oil remaining on the cuttings as measured by either a reverse phase extraction test or GC/MS, and
- The stock synthetic fluids must meet mass ratio polynuclear aromatic hydrocarbon (PAH) limits, sediment toxicity (10-day), and biodegradation rate prior to combination with other components of the drilling fluid system.

C.1.1.2 ELGs for Deck Drainage (002) per 40 CFR 435 Subpart A and Subpart D

EPA determined that the BPT available for treatment of deck drainage is a sump and skim pile system. Oil and water are gravity-separated in the sump, and the oil is sent off-site to an oil treatment system. After treatment in an oil-water separator (OWS), clean water is discharged, and oily water is stored aboard until transferred to an approved treatment and disposal site. The Permit requires that deck drainage contaminated with oil and grease is processed through an OWS prior to discharge, and prohibits the discharge of free oil in deck drainage discharges.

The ELGs for BAT and BCT require a limitation of no discharge of free oil as determined by the presence of film, sheen, or a discoloration of the surface of the receiving water for deck drainage discharges. Contaminated deck drainage treated for removal of oil and/or grease can also comply with no free oil by conducting an optional Static Sheen Test prior to discharge.

C.1.1.3 ELGs for Domestic Wastewater (003) per 40 CFR 435 Subpart A and Subpart D

For domestic wastewater (referred to as sanitary waste in the ELGs), the ELGs for BPT and BCT require TRC to be maintained as close to 1.0 mg per liter (mg/L) as possible for facilities that are continuously manned by 10 or more staff (M10). The ELGs also require no discharge of floating solids for facilities that continuously manned by nine or fewer staff or are intermittently manned at any number (M9IM).

The ELGs requiring TRC to be a minimum of, and kept as close as practicable to, 1.0 mg/L is to ensure that adequate disinfection of bacteria is achieved and is considered a surrogate limit for fecal coliform and enterococci bacteria.

C.1.1.4 ELGs for Graywater (004) per 40 CFR 435 Subpart A and Subpart D

For graywater (referred to as domestic waste in the ELGs) discharges, the ELGs prohibit the discharge of floating solids, garbage or foam.

C.1.1.5 ELGs for Produced Water (015) per 40 CFR 435 Subpart A and Subpart D

The evaluation conducted by EPA during promulgation of the ELGs in 1996, led to a determination that Cook Inlet is unique compared to other coastal locations in the U.S. This uniqueness allows for the discharge of produced water where everywhere else, it is prohibited. The ELGs for produced water discharge to Cook Inlet requires an oil and grease average monthly limit (AML) of 29 mg/L a maximum daily limit (MDL) of 42 mg/l. In formulating those ELGs, EPA examined all existing facilities and the pollutants that could be expected to be discharged in produced water, and concluded that they could be appropriately controlled by the oil and grease limits when discharging to Cook Inlet. Therefore, DEC cannot impose more stringent TBELs using case-by-case BPJ, such as a no discharge of produced water limitation.

C.1.1.6 ELGs for Well Treatment (016), Workover (017), and Completion (018) Fluids per 40 CFR 435 Subpart A and Subpart D

Due to the similar nature of these well fluids to produced water, the ELGs apply the same oil and grease limits as produced water: MDL of 42 mg/L and an AML of 29 mg/L.

C.1.2 TBELs Developed Using Case-by-Case Best Professional Judgement

In situations where ELGs have not been developed or have not considered specific discharges or pollutants, a regulatory agency can develop case-by-case TBELs using BPJ. Where national ELGs have not been developed, or did not consider specific pollutant parameters in discharges, the same performance-based approach applied to develop national ELGs is applied to a specific industrial facility using BPJ. The Permit contains TBELs developed on case-by-case basis using BPJ derived during development of the 1999 GP and the 2007 GP. The Department has reevaluated these BPJ limits to ensure compliance with Section 402 of the CWA.

Per Section 402 of the CWA, developing TBELs using case-by-case BPJ requires the permitting

authority to consider the age of equipment and facilities involved, the process employed, the engineering aspects of the application of various types of control techniques, process changes, the cost of achieving such effluent reduction, non-water quality environmental impact (including energy requirements), the cost of implementing these conditions relative to the environmental benefits achievable, and such other factors as deemed appropriate. The Department has evaluated the original TBELs developed by EPA using case-by-case BPJ in relation to age of equipment and current engineering aspects of control techniques, as well as other pertinent considerations. The Department has determined that these TBELs established in 1999 and 2007 are still directly applicable to the Permit. However, DEC will ultimately compare these TBELs to applicable WQBELs to determine which is more stringent for final limits.

The TBELs developed previously using case-by-case BPJ include:

- pH limits of 6.0 to 9.0 standard units for produced water (015), well treatment (016), workover (017), completion (018), and test (019) fluids;
- no free oil based on receiving water observations for blowout preventer fluid (006), excess cement slurry (012), mud, cuttings, cement at the seafloor and based on either surface observations or Static Sheen when observations cannot be made for uncontaminated ballast water (010), bilge water (011), treatment (016), workover (017), treatment (018) fluids, and test fluids (019);
- oil and grease limits of 42 mg/L as an MDL and 29 mg/L as an AML for test fluids (019).

In the 2007 GP, TBELs were developed using case-by-case BPJ for MDLs and AMLs for five-day biochemical oxygen demand (BOD_5) and total suspended solids (TSS) in domestic wastewater (003). DEC is retaining these TBELs but modifying the basis to appropriately cite the state authority under 18 AAC 72 for regulating domestic wastewater, which includes domestic wastewater (003) and graywater (004). See Fact Sheet Section 3.5.4 for a clarifications and discussions. In addition, DEC is adding a new TBEL developed using case-by-case BPJ for a maximum limit for TRC of 1 mg/L after dechlorination. DEC requires dechlorination as a technology requirement. This TRC maximum limit was first introduced in the 2015 Exploration GP, which will be superseded by the Permit. Lastly, DEC applies this same 1 mg/L maximum limit to graywater that is treated with marine sanitation devices (MSDs) and imposes dechlorination treatment prior to discharge. See also Fact Sheet Section 6.2.3.4.

In addition to these historic TBELs developed using case-by-case BPJ, DEC is adopting a new one for Class C3 drilling fluids that include barite and may be used in geotechnical surveys or HDD projects. There are currently no ELGs applicable to geotechnical surveys or HDD drilling projects and these drilling applications are not related to oil and gas extraction. However, because Class C3 drilling fluids have similar characteristics as those used in oil and gas, DEC is adopting limits for stock barite of 1 mg/kg mercury and 3 mg/kg cadmium and citing 40 CFR 435 as the basis. The following sections discuss these TBELs using case-by-case BPJ in more detail.

C.1.2.1 TBELs Using Case-by-Case BPJ for Drilling Fluids and Drill Cuttings (001)

C.1.2.1.1 Cadmium and Mercury TBELs for drilling fluids for Geotechnical Surveys and Horizontal Direction Drilling Containing Barite

Because the use of barite in non-oil and gas drilling fluids come from the same sources, uses the same drilling technology, and can have similar environmental concerns as that used in oil and gas, the Department is adopting the 3 mg/kg limit for cadmium and the 1 mg/kg limit for mercury in the stock barite. These limits only apply to drilling fluids where barite is an ingredient (Class C3 Fluids).

C.1.2.1.2 TBELs Using Case-by-Case BPJ for Domestic Wastewater (003) and Graywater (004)

The 1986 GP required facilities discharging to state waters to meet the minimum secondary treatment standards per 18 AAC 72.050, which are 30 mg/L BOD_5 and 30 mg/L TSS, respectfully as AMLs and 60 mg/L as MDLs. Existing M10 and M9IM facilities treated domestic wastewater using various treatment systems including MSDs, biological treatment units (BTUs), and combination of MSDs and BTUs during that permit cycle. Nearly all facilities had difficulty meeting secondary treatment standards for TSS, and the M9IM systems using biological treatment had difficulties meeting BOD_5 standards even when the systems were operated correctly. In the 1999 GP, EPA developed TBELs based on case-by-case BPJ using data available from existing oil and gas platforms operating in Cook Inlet. The limits developed were categorized according to M10 versus M9IM and by MSDs versus BTUs. Only the M10 biological systems could meet secondary standards. The M10 and M9IM MSD systems could meet secondary standards for BOD_5, but not for TSS. The M9IM BTUs could not meet secondary standards for either BOD_5 or TSS. However, BTUs that treated wastewater derived from filtered sea water for flushing could apply an intake allowance per 18 AAC 83.545 to meet the TSS limits.

In the 2007 GP, EPA reevaluated these limits based on representative data collected during the previous permit cycle. The evaluation resulted in retaining the limits. In a similar manner, DEC reviewed data collected since issuance of the 2007 GP to evaluate the ability of treatment systems currently used to attain the permit limits. In addition, during issuance of AKG315100 – Mobile Oil and Gas Exploration Facilities in State Waters in Cook Inlet (2015 Exploration GP), DEC reviewed other pollution control equipment currently available and engineering aspects to inform the decision of retaining these previously developed TBELs using BPJ. DEC determined that the existing domestic wastewater limits are attainable using properly operated and maintained treatment systems on oil and gas facilities operating in Cook Inlet. Because these limits are less stringent than secondary treatment for TSS, any new applicant must obtain a waiver to minimum treatment requirements (See Fact Sheet Sections 3.5.4 and 6.2.3.4).

During issuance of 2015 Exploration GP, DEC adopted a TBEL using case-by-case BPJ for a maximum limit of 1 mg/L for total residual chlorine. This was a TBEL based on application of readily available and economically achievable dechlorination treatment technology. Hence, permittees must dechlorinate. Because some existing facilities route graywater through MSDs to attain primary treatment and the MSDs chlorinate and dechlorinate, DEC is applying the maximum 1 mg/L TRC limit to situations where MSDs are used to meet primary treatment prior to discharging (See Fact Sheet Sections 3.5.4 and 6.2.3.4). This is appropriate given that DEC authority under 18 AAC 72 does not distinguish separate treatment requirements for Discharge 003 versus Discharge 004 as both are considered domestic wastewater.

C.1.2.1.3 Discharges with No Free Oil Limitations Developed Using Case-by-Case BPJ

The following miscellaneous discharges are controlled via TBELS developed using case-by-case BPJ for no free oil:

Blowout preventer fluid (visual only)	(006)
Uncontaminated ballast water	(010)
Bilge water	(011)
Excess cement slurry (visual only)	(012)
Muds, cuttings, and cement at the seafloor (visual only)	(013)
Water flood waste water	(014)
Treatment fluids	(016)
Workover fluids	(017)
Completion fluids	(018)
Test fluids	(019)

Limitations for Discharges 006 and 010 through 014 were not included in the ELGs. Although discharges 016 through 018 were included in the ELGs, the ELGs did not control free oil. In the 1999 GP, EPA adopted the no free oil TBELs using case-by-case BPJ. DEC has evaluated these TBELS and has determined the evaluation conducted by EPA is still appropriate. Compliance with the limitation of no free oil will be determined by the visual sheen test except for discharges that require treatment in an OWS, or other oil removal process, prior to discharge. Bilge water, contaminated ballast water, treatment fluids, workover fluids, completion fluids, and test fluids must treat effluent in an OWS. The well fluids require compliance using the Static Sheen Test but bilge and treated ballast water complies using visual observations of the receiving water, or the Static Sheen Test when observations are not possible such as when ice conditions prevent observation of the water surface.

C.1.2.1.4 Discharges With pH Limits Developed Using Case-by-Case BPJ

Similar to limitations for no free oil, EPA adopted pH limits of between 6.0 and 9.0 standard units for discharges of produced water (015) treatment fluids (016), workover fluids (017), and completion fluids (018). Although these discharges were included in the ELGs, the ELGs did not include pH limits and pH was considered an appropriate control for chemical additives. EPA also applied the TBEL developed using case-by-case BPJ for pH for test fluids (019), which was not a discharge included in the ELGs. DEC has evaluated these TBELs and has determined the evaluation conducted by EPA is still appropriate.

C.1.2.1.5 Oil and Grease Limitation for Test Fluids Using Case-by-Case BPJ

Test fluids (019) were not included in the ELGs but are anticipated to have similar characteristics as formation water but may also contain fluids injected downhole similar to treatment, workover, and completion fluids. Previous Cook Inlet permits established oil and grease limits based on case-by-case BPJ referencing the ELG limits for produce water, an AML of 29 mg/L and an MDL of 42 mg/L. The Department has evaluated these BPJ limits and concurs with the previous determination and retains these limits in the Permit.

C.2 WATER QUALITY-BASED EFFLUENT LIMITS

C2.1 Statutory and Regulatory Basis

Per 18 AAC 83.435(a), an APDES permit must include conditions (e.g., WQBELs) in addition to, or more stringent than established TBELs as necessary to protect WQS. When evaluating if WQBELs are needed in addition to TBELs, the permitting authority conducts a reasonable potential analysis (RPA) based on pertinent pollutants of concern (POCs). Pertinent POCs are those that the Department considers as having the potential to exceed water quality criteria at the point of discharge or at the boundary of a mixing zone, if authorized. If a mixing zone is authorized, the Department may consider the dilution available in the receiving water in the analysis. Per 18 AAC 83.435(c), DEC must also use procedures that account for effluent variability (e.g., maximum expected effluent concentrations [MEC] and coefficient of variation [CV]), existing controls on point sources (e.g., treatment systems), and nonpoint sources of pollution (e.g., ambient receiving water concentrations). The Department developed and implemented a *Reasonable Potential Analysis and Effluent Limits Development Guide, June 30, 2014 (RPA/WQBEL Guidance)* and associated spreadsheet tool that were used in development of the WQBELs in the Permit.

C2.2 Reasonable Potential Analysis

The *RPA/WQBEL Guidance* uses statistical methods to estimate MECs based on the 99th percentile at a 95 % confidence interval. Using a mass balance approach, the RPA projects the concentration at the boundary of a mixing zone, if authorized. Because DEC has authorized acute and chronic mixing zones, the mass balance procedure evaluates if the effluent exceeds, or contributes to an exceedance, of water quality criteria at the boundary of either the acute or the chronic mixing zone. Based on the RPA summarized in Appendix B, the Department has determined there is a reasonable potential for the

discharge to exceed, or contribute to an exceedance of, the chronic marine temperature criterion at the boundary of the chronic mixing zone for total aromatic hydrocarbons (TAH) in produced water from in all but one discharge of produce water; the Tyonek A Platform has reasonable potential for copper rather than TAH. Hence, a WQBEL is required for TAH, or copper, for each produced water discharge. DEC also determined that certain metals have reasonable potential to exceed, or contribute to an exceedance of, the acute marine criterion for certain metals at the boundary of the acute mixing zone for produced water. Accordingly, WQBELs for the metals copper, silver, or zinc are required for various facilities; only one of these metals have reasonable potential for each produced water discharge. There were no other discharges authorized under the Permit that resulted in a reasonable potential for numeric limit. Reasonable potential for certain narrative criteria is discussed in Section C.2.6. The numeric WQBELs for TAH and the metals have been developed per 18 AAC 83.435 to be consistent with the calculated available WLA and stringent enough to ensure compliance with WQS.

C.2.3 Wasteload Allocations

In the context of this section, a WLA is the concentration of a pollutant that can be discharged to the receiving water and comply with the acute (a) or chronic (c) water quality criteria ($WQC_{a,c}$), accounting for ambient concentrations and authorized acute or chronic dilution factors ($DF_{a,c}$) in the mixing zones, if applicable. The Department has authorized various chronic dilution factors for TAH, or copper, in produced water and various acute dilution factors for copper, silver, or zinc. For TAH, no ambient (Amb) concentrations of TAH were detected in the data collected near produced water outfalls during Integrated Cook Inlet Monitoring and Assessment Program (ICIEMAP) in 2008 and 2009. However, data for copper, silver, and zinc were above detection and the 85th percentile of the data is used to represent ambient concentrations for metals (See Appendix A). The WLA for TRC is calculated by rearranging Equation B-3 in Appendix B and substituting WQC for receiving water concentration and WLA for the maximum expected concentration. The resulting mass balance equation is:

$$WLA_{a,c} = DF_{a,c}\,(WQC_{a,c} - Amb) + Amb$$

C.2.4 WQBEL for TAH on Trading Bay Production Facility Produced Water Discharge

This section describes the WQBEL procedure for TAH for the produced water discharge at the TBPF. Each other facility discharging produced water also requires a WQBEL for TAH, or copper, and the procedures are identical as that for TBPF except the input variables are different. DEC describes the procedure using the TBPF as an example and then provides a summary of the results of the other facilities in Section C.3.

The RPA revealed that TAH has reasonable potential to exceed, or contribute to an exceedance of, the chronic water quality criterion for TAH at the boundary of the chronic mixing zone for the TBPF, requiring development of WQBELs. The authorized chronic dilution factor, DF_c, for the TBPF chronic mixing zone is 1,335. The MDL and AML are based on an MEC derived from mass balance equal to 13,350 micrograms per liter (µg/L), a calculated CV of 0.21, and an assumed four samples per month. The calculations for the MDL and AML for TAH on the TBPF produced water discharges is shown below.

<u>Input Parameters for copper WQBEL Development</u>

- The chronic wasteload allocation (WLA_c) for TAH is 13,350 µg/L
- Coefficient of Variation (CV) = 0.21
- Sampling Interval = 4 samples/month
- z statistic for 99th percentile probability basis (Z_{99}) = 2.326
- z statistic for 95th percentile probability basis (Z_{95}) = 1.645

Calculations

Determine Long Term Averages (LTAs)

There is no acute criteria for TAH. Therefore, the chronic LTA, LTAc is calculated as follows:

$$LTA_c = WLA\ [\exp(0.5\sigma_4^2 - Z_{99}\sigma_4)],\ \text{where}\ \sigma_4^2 = \ln(CV^2/4 + 1)$$

$$WLA = 13{,}350\ \mu g/l,\ CV = 0.21,\ Z_{99} = 2.326,\ \text{and}\ \sigma_4^2 = 0.011$$

LTA_c = 10,521 μg/L

- **Determine the most limiting (lowest) LTA**

LTA_c is most limiting = 10,521 μg/L

Calculate the MDL and AML

$$MDL = LTA_a\ [\exp(Z_{99}\sigma - 0.5\sigma^2)],\ \text{where}\ \sigma^2 = \ln(CV^2 + 1)$$

$$CV = 0.21,\ Z_{99} = 2.326,\ \text{and}\ \sigma^2 = 0.0432$$

MDL = 16,695.5 μg/L
USE 16,695 μg/L

$$AML = LTA_a\ [\exp(Z_{95}\sigma_4 - 0.5\sigma_4^2)],\ \text{where}\ \sigma_4^2 = \ln(CV^2/4 + 1),$$

$$CV = 0.851,\ Z_{95} = 1.645,\ \text{and}\ \sigma_4^2 = 0.1664$$

AML = 12,430.8 μg/L
USE 12,430 μg/L

C.2.5 WQBEL for Copper on Trading Bay Production Facility Produced Water Discharge

This section describes the WQBEL procedure for copper for the produced water discharge at the TBPF. Each other facility discharging produced water also requires a WQBEL for either copper, silver, or zinc and the procedures are identical as that for TBPF except the input variables and driving parameters are different. DEC describes the procedure using the TBPF as an example and then provides a summary of the results of the other facilities in Section C.3.

The RPA revealed that copper has reasonable potential to exceed, or contribute to an exceedance of, the acute water quality criterion for copper at the boundary of the chronic mixing zone for the TBPF, requiring development of WQBELs. The authorized dilution factor for the TBPF chronic mixing zone is 4.5. The MDL and AML are based on an MEC derived from mass balance equal to 23.82 μg/L, a calculated CV of 0.21, and an assumed four samples per month. The calculations for the MDL and AML for copper on the TBPF produced water discharges is shown below.

Input Parameters for copper WQBEL Development

- The chronic wasteload allocation (WLA_c) for copper is 3,751 μg/L
- The acute wasteload allocation (WLA_a) for copper is 22.78 μg/L
- Coefficient of Variation (CV) = 0.502
- Sampling Interval = 4 samples/month
- z statistic for 99th percentile probability basis (Z_{99}) = 2.326
- z statistic for 95th percentile probability basis (Z_{95}) = 1.645

Calculations

Determine Long Term Averages (LTAs)

The LTAs acute (a) and chronic (c) exposure were calculated as follows:

$LTA_a = WLA\ [\exp(0.5\sigma^2 - Z_{99}\sigma)]$, where $\sigma^2 = \ln(CV^2 + 1)$

WLA = 22.78µg/L, CV = 0.502, Z_{99} = 2.326, and $\sigma^2 = 0.225$

LTA_a = 8.46 µg/L

$LTA_c = WLA\ [\exp(0.5\sigma_4^2 - Z_{99}\sigma_4)]$, where $\sigma_4^2 = \ln(CV^2/4 + 1)$

WLA = 3,751 µg/l, CV = 0.502, Z_{99} = 2.326, and $\sigma_4^2 = 0.0612$

LTA_c = 2,666 µg/L

- **Determine the most limiting (lowest) LTA**

LTA_a is most limiting = 8.46 µg/L

Calculate the MDL and AML

$MDL = LTA_a\ [\exp(Z_{99}\sigma - 0.5\sigma^2)]$, where $\sigma^2 = \ln(CV^2 + 1)$

CV = 0.502, Z_{99} = 2.326, and $\sigma^2 = 0.225$

MDL = 22.78 µg/L
USE 22.0 µg/L

$AML = LTA_a\ [\exp(Z_{95}\sigma_4 - 0.5\sigma_4^2)]$, where $\sigma_4^2 = \ln(CV^2/4 + 1)$,

CV = 0.851, Z_{95} = 1.645, and $\sigma_4^2 = 0.1664$

AML = 12.32 µg/L
USE 12.0 µg/L

C.2.6 Other Numeric or Narrative Water Quality-Based Effluent Limits and Monitoring

In addition to the parameters evaluated in the RPA, the limited and monitoring parameters in the existing Permit were reviewed to confirm they are appropriate for inclusion, should be modified, or removed from the reissued Permit as summarized below.

C.2.6.1pH

The criteria for pH is no less than 6.5 SU and not greater than 8.5 SU. Discharges of produced water (Discharge 015), treatment fluids (Discharge 016), workover fluids (017), completion fluids (Discharge 018), and test fluids (Discharge 019) have a TBEL developed using case-by-case BPJ per Section B.1.2.1.5 applied at the compliance point prior to commingling. DEC has assessed the impacts of authorizing these limits and determined that these limits would not result in exceeding water quality criteria at the boundary of the chronic mixing zone; the criteria will be reached in close proximity of the discharge due to available dilution and buffering capacity of the receiving water. Hence, the water quality criteria for pH can be exceeded within the mixing zone but not beyond the TBEL for pH (i.e., 6.0 to 9.0 SU).

C.2.6.2 Narrative Requirements

Oil and Grease (Visual Sheen): Per 18 AAC 70.020(b)(17)(A)(i), there may be no concentrations of petroleum hydrocarbons in shoreline or bottom sediments that cause deleterious effects to aquatic life. Surface waters and adjoining shorelines must be virtually free from floating oil, film, sheen or discoloration. This narrative WQBEL is compared to the no free oil TBEL in Section B.3.

Residues: Residues include floating solids, debris, sludge, deposits, foam, or other objectionable conditions. Per 18 AAC 70.020(b)(20)(A)(ii), a discharge "may not, alone or in combination with other substances, cause a film, sheen, or discoloration on the surface of the water or adjoining shorelines; cause leaching of toxic or deleterious substances; or cause a sludge, solid, or emulsion to be deposited beneath or upon the surface of the water, within the water column, on the bottom, or upon adjoining shorelines." Compliance with this residue criteria will be applied as a general permit condition for all discharges.

C.3 DETERMINATION OF MOST STRINGENT EFFLUENT LIMITS

Per the *RPA/WQBEL Guidance*, only those parameters that exceed or contribute to an exceedance of water quality criteria require WQBELs in permits. The 2007 GP did not follow this procedure and included WQBELs for TAH based on chronic criteria and a suite of metals including copper, manganese, mercury, silver, and zinc for the acute criteria. During evaluation of WQBELs for the Permit, most resulting WQBELs for the driving parameters were more stringent than those in the 2007 GP. However, in two instances the calculated MDL or AML were less stringent to those in the 2007 GP; the development of WQBELs for GPTF resulted in calculation of an MDL and AML for TAH that were less stringent than those in the 2007 GP and the Dillon had a less stringent MDL for TAH. The current MDL/AML for GPTF was determined to be 29/20 mg/L; whereas, the 2007 MDL/AML for GPTF was 20/14 mg/L. For the Dillon, the recent MDL was 43 mg/L and the 2007 MDL was 42 mg/L. Review of the characterization data for GPTF indicates that the maximum observed concentration during the period of review was 19.55 mg/L and the average was 11.7 mg/L. Given that the 2007 limits appear to be attainable, DEC is using discretion and retaining the 2007 limits for GPTF and Dillon in the Permit. In addition, the extraneous metal limits imposed by the 2007 GP appear to be attainable and are also being retained at a reduced frequency for the next permit term. Data collected during the next permit term will be use to evaluate the variability of the metals in the effluent to ensure extraneous WQBEL for metals are not necessary to control the effluent before eliminating them in lieu of imposing a single metal limits a surrogate for all metals. Table 55provides a summary of the primary limits for the chronic driving parameters developed for the Permit and compared to those same parameter limits in the 2007 GP.

Table 55: 2007 GP to Current Permit Comparison of Chronic WQBELs for Produced Water

Facility	Parameter	Units	2007 GP		Current Permit	
			MDL	AML	MDL	AML
TBPF	TAH	mg/L	27	18	17	12
MGS Onshore	TAH	mg/L	32	24	28	20
GPTF [1]	TAH	mg/L	20	14	20	14
Baker	TAH	mg/L	257	128	47	34
Bruce	TAH	mg/L	143	78	46	31
Dillon [1]	TAH	mg/L	42	31	42	31
Tyonek A	Copper	µg/L	1.033	328	790	247
Osprey [2]	TAH	mg/L	--	--	9.0	7.7

Notes:
1. Limits from the 2007 GP were retained for the Current Permit.
2. The Osprey Platform was not previously authorized to discharge produced water.

Similar to WQBELs established based on chronic criteria, the WQBELs for the metals driving the size of the acute mixing zone are more stringent than the limits for these parameters in the 2007 GP. Table 56 provides a comparison between the metal limits for driving parameters between the 2007 GP and the current Permit.

Table 56: 2007 GP to Current Permit Comparison of Acute WQBELs for Produced Water

Facility	Parameter	Units	2007 GP		Current Permit	
			MDL	AML	MDL	AML
TBPF	Copper	µg/L	117	47	22	12
MGS Onshore [1]	Silver	µg/L	149	46	48	19
GPTF [1]	Copper	µg/L	130	67	54	21
Baker	Zinc	mg/L	14.3	6.7	13	6
Bruce	Zinc	mg/L	47	28	25	10
Dillon [1]	Silver	µg/L	55	28	48	19
Tyonek A [2]	Copper	µg/L	1,033	328	790	247
Osprey [3]	Copper	µg/L	--	--	195	97

Notes:
1. Because the characterization data from MGS Onshore was used as representative of the Dillon Platform, these facilities have the same limits for Silver.
2. Because copper was the driving parameter for both the chronic and acute mixing zones at the Tyonek A Platform, the same limit for copper applies.
3. The Osprey Platform was not previously authorized to discharge produced water.

DEC compared the narrative water quality criteria for oil and grease (visible sheen) to the TBELs based on observation of receiving water. Because the narrative WQBEL includes additional protections for sediment and shoreline, DEC has determined the WQBEL narrative is more stringent and is applying visual observation of sheen to in lieu of the ELG of no free oil except where the ELGs dictate that compliance is only by the Static Sheen Test (i.e., discharges of oil and gas drilling fluids and drill cuttings). In all other cases under the ELGs or TBELs developed previously using case-by-case BPJ compliance is by observation of the water surface similar to that for the narrative water quality criteria for oil and grease (visible sheen). DEC also has determined that compliance with the water quality narrative using the Static Sheen Test in situations where visual observations are not possible (e.g., during periods of ice cover or broken ice conditions) is acceptable. A summary table is provided in Fact Sheet Section 7.0. There are no other WQBELs, numeric or narrative, to compare to TBELs.

Appendix D MIXING ZONE ANALYSIS CHECKLIST

Mixing Zone Authorization Checklist

based on Alaska Water Quality Standards (2003)

The purpose of the Mixing Zone Checklist is to guide the permit writer through the mixing zone regulatory requirements to determine if all the mixing zone criteria at 18 AAC 70.240 through 18 AAC 70.270 are satisfied, as well as provide justification to authorize a mixing zone in an APDES permit. In order to authorize a mixing zone, all criteria must be met. The permit writer must document all conclusions in the permit Fact Sheet, however, if the permit writer determines that one criterion cannot be met, then a mixing zone is prohibited, and the permit writer need not include in the Fact Sheet the conclusions for when other criteria were met.

Criteria	Description	Answer & Resources	Regulation
Size	Is the mixing zone as small as practicable? - Permit writer conducts analysis and documents analysis in Fact Sheet at: ►Section 6.2.3.6.9 and 6.2.4 Mixing Zone Sizing. All Mixing Zones meet aquatic life and human health criteria at the boundary of the chronic mixing zone; no lethality to passing organisms, and no toxic effect in water column, sediment, or biota outside the boundary.	Answer: Yes Technical Support Document for Water Quality Based Toxics Control Fact Sheet, Section 6.2.4 Fact Sheet, Section 6.2.3.6.9 DEC RPA & WQBEL Guide EPA Permit Writers' Manual	18 AAC 70.240 (a)(2) 18 AAC 70.245 (b)(1) - (b)(7) 18 AAC 70.255(e) (3) 18 AAC 70.255 (d)
Technology	Were the most effective technological and economical methods used to disperse, treat, remove, and reduce pollutants? If yes, describe methods used in Fact Sheet at Section 6.2.5 Technology. All treatment systems meet the highest statutory and regulatory requirements.	Answer: Yes Fact Sheet, Section 6.2.5	18 AAC 70.240 (a)(3)
Low Flow Design	For river, streams, and other flowing fresh waters. - Determine low flow calculations or documentation for the applicable parameters. Justify in Fact Sheet	N/A	18 AAC 70.255(f)

Criteria	Description	Answer & Resources	Regulation
Existing use	Does the mixing zone…		
	(1) partially or completely eliminate an existing use of the waterbody outside the mixing zone? If yes, mixing zone prohibited.	Answer: No Fact Sheet Section 6.2.6	18 AAC 70.245(a)(1)
	(2) impair overall biological integrity of the waterbody? If yes, mixing zone prohibited.	Answer: No Fact Sheet Section 6.2.6 Fact Sheet Section 6.2.8 Fact Sheet Section 6.2.11	18 AAC 70.245(a)(2)
	(3) provide for adequate flushing of the waterbody to ensure full protection of uses of the waterbody outside the proposed mixing zone? If no, then mixing zone prohibited.	Answer: Yes Fact Sheet Appendix A Fact Sheet Section 6.2.1	18 AAC 70.250(a)(3)
	(4) cause an environmental effect or damage to the ecosystem that the department considers to be so adverse that a mixing zone is not appropriate? If yes, then mixing zone prohibited.	Answer: No Fact Sheet Section 6.2.1 Fact Sheet Section 6.2.7 Fact Sheet Section 6.2.8 Fact Sheet Section 6.2.10	18 AAC 70.250(a)(4)
Human consumption	Does the mixing zone…		
	(1) produce objectionable color, taste, or odor in aquatic resources harvested for human consumption? If yes, mixing zone may be reduced in size or prohibited.	Answer: No Fact Sheet Section 6.2.7	18 AAC 70.250(b)(2)
	(2) preclude or limit established processing activities of commercial, sport, personal use, or subsistence shellfish harvesting? If yes, mixing zone may be reduced in size or	Answer: No Fact Sheet Section 6.2.6 Fact Sheet Section 6.2.7	18 AAC 70.250(b)(3)

Criteria	Description	Answer & Resources	Regulation
	prohibited.		
Spawning Areas	Does the mixing zone…		
	(1) discharge in a spawning area for anadromous fish or Arctic grayling, northern pike, rainbow trout, lake trout, brook trout, cutthroat trout, whitefish, sheefish, Arctic char (Dolly Varden), burbot, and landlocked coho, king, and sockeye salmon? If yes, mixing zone prohibited.	Answer: No Fact Sheet Section 6.2.9	18 AAC 70.255 (h)
Human Health	Does the mixing zone…		
	(1) contain bioaccumulating, bioconcentrating, or persistent chemical above natural or significantly adverse levels? If yes, mixing zone prohibited.	Answer: No Fact Sheet Section 6.2.7 Fact Sheet Section 6.2.8	18 AAC 70.250 (a)(1)
	(2) contain chemicals expected to cause carcinogenic, mutagenic, tetragenic, or otherwise harmful effects to human health? If yes, mixing zone prohibited.	Answer: No Fact Sheet Section 6.2.8	
	(3) Create a public health hazard through encroachment on water supply or through contact recreation? If yes, mixing zone prohibited.	Answer: No Fact Sheet Section 6.2.6	18 AAC 70.250(a)(1)(C)
	(4) meet human health and aquatic life quality criteria at the boundary of the mixing zone? If no, mixing zone prohibited.	Answer: Yes Fact Sheet Section 6.2.4 Fact Sheet Section 6.2.8 Fact Sheet Section 6.2.10	18 AAC 70.255 (b),(c)

Criteria	Description	Answer & Resources	Regulation
	(5) occur in a location where the department determines that a public health hazard reasonably could be expected? If yes, mixing zone prohibited.	N/A Marine Water	18 AAC 70.255(e)(3)(B)
Aquatic Life	Does the mixing zone…		
	(1) create a significant adverse effect to anadromous, resident, or shellfish spawning or rearing? If yes, mixing zone prohibited.	Answer: No Fact Sheet Section 6.2.9	18 AAC 70.250(a)(2)(A-C)
	(2) form a barrier to migratory species? If yes, mixing zone prohibited.	Answer: No Fact Sheet Section 6.2.4 Fact Sheet Section 6.2.9	
	(3) fail to provide a zone of passage? If yes, mixing zone prohibited.	Answer: No Fact Sheet Section 6.2.4 Fact Sheet Section 6.2.9	
	(4) result in undesirable or nuisance aquatic life? If yes, mixing zone prohibited.	Answer: No Fact Sheet Section 5.3.7	18 AAC 70.250(b)(1)
	(5) result in permanent or irreparable displacement of indigenous organisms? If yes, mixing zone prohibited.	Answer: No Fact Sheet Section 6.2.7	18 AAC 70.255(g)(1)
	(6) result in a reduction in fish or shellfish population levels? If yes, mixing zone prohibited.	Answer: No Fact Sheet Section 6.2.7	18 AAC 70.255(g)(2)
	(7) prevent lethality to passing organisms by reducing the size of the acute zone? If yes, mixing zone prohibited.	Answer: No Fact Sheet Section 6.2.4	18 AAC 70.255(b)(1)

Criteria	Description	Answer & Resources	Regulation
	(8) cause a toxic effect in the water column, sediments, or biota outside the boundaries of the mixing zone? If yes, mixing zone prohibited.	Answer: No Fact Sheet Section 6.2.4 Fact Sheet Section 6.2.8	18 AAC 70.255(b)(2)
Endangered Species	Are there threatened or endangered species (T/E spp) at the location of the mixing zone?If yes, are there likely to be adverse effects to T/E spp based on comments received from USFWS or NOAA. If yes, will conservation measures be included in the permit to avoid adverse effects? If yes, explain conservation measures in Fact Sheet. If no, mixing zone prohibited.	Answer: Yes Fact Sheet Section 3.3.1 Fact Sheet Section 6.2.8 Fact Sheet Section 6.2.11 Fact Sheet Section 12.1	Program Description, 6.4.1 #5 18 AAC 70.250(a)(2)(D)