ConocoPhillips Alaska, Inc.

OIL DISCHARGE PREVENTION AND CONTINGENCY PLAN

KUPARUK RIVER UNIT – KUPARUK PIPELINE
NORTH SLOPE, ALASKA

ConocoPhillips
Alaska, Inc.

March 2013

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STATEMENT OF CORPORATE COMMITMENT

OIL DISCHARGE PREVENTION AND CONTINGENCY PLAN
KUPARUK FIELD AND PIPELINE
NORTH SLOPE, ALASKA

This Oil Discharge Prevention and Contingency Plan (ODPCP) has been prepared for all activities conducted by ConocoPhillips Alaska, Inc. (CPAI), in the Kuparuk Field, including the Pipeline Right-of-Way (ROW).

MANAGEMENT APPROVAL AND MANPOWER AUTHORIZATION

This plan is approved for implementation as herein described. Manpower, equipment, and materials will be provided as required in accordance with this plan.

Tyrone Maxey
Manager, Greater Kuparuk Area Operations
ConocoPhillips Alaska, Inc.

08/14/14
Date

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RECORD OF REVISIONS

REVISION NUMBER	REVISION DATE	DESCRIPTION OF REVISION
1	March 2013	Updated acronyms, Section 2.5.2 (leak detection software), Section 2.6, Part 3, and Appendix B tank tables.
2	May 2013	Updated Table 2-2 and Appendix B tank tables.
3	June 2013	Update and add Rain for Rent tank information in Appendix B, Table B-3.
4	Sept. 2013	Update Part 2 Table 2-2 and Section 2.5.2; update Figure A-4; update Table B-1 for Tank T-EF06.
5	December 2013	Update Appendix A (Figures A-70a and A-70b), and update Appendix B (Tables B-1, B-2, B-3 and B-4)
6	January 2014	Update Appendix B, Table B-3 to add Atigun 1128 and four MagTec tanks; update inspection dates for Atigun 125, 126, & 127.
7	March 2014	Add Figure 3-2; update Section 3.10; and updated tank tables B-1 and B-4 in Appendix B.
8	May 2014	Add DOT Letter of Approval, dated April 24, 2014. Update Manager, Greater Kuparuk Area Operations. Update Waivers in Effect: remove July 1, 2011 waiver and add April 8, 2014 waiver; update affected pages in Table 2-2, Part 2.6, and Appendix B, Table B-1. Update U.S. Department of Transportation Summary: Type of Oil and Volume of Worst Case Discharge, Update Part 3.3 (Command System) and add new figures, Update Part 3.9 (Training and Drills, and Recordkeeping).
9	July 2014	Update Introduction to include a Plan Supplemental Documentation section. Update Table 1-9, 1-13, and 1-14: 59 bbl storage bladder replaced with 2,400 gallon portable storage unit. Update Table 2-2 to include additional tank truck loading areas. Update Section 3.10 to include general property summaries of oil that may be discharged at the facility. Update Table B-3 Rented or Leased Portable ADEC Regulated Storage Tanks: TANKO 122 inspection date.
10	October 2014	Update Management Approval and Manpower Authorization signature. Update Section 2.6 to add ADEC approval letter dated October 27, 2014. Update Table B-3 to add new TANKO tanks T-22 through T-33.
11	November 2014	Removal of references to the Oliktok Natural Gas Liquid Pipeline. Update OPA 90 USDOT. Update Section 3.1 to revise Kuparuk and Kuparuk satellite field ownerships.

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OIL DISCHARGE PREVENTION AND CONTINGENCY PLAN
KUPARUK FIELD AND PIPELINE, NORTH SLOPE, ALASKA

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LIST OF ACRONYMS

%	percent
°C	degrees Celsius
°F	degrees Fahrenheit
AAC	Alaska Administrative Code
AAI	ARCO Alaska, Inc.
ACP	Area Contingency Plan
ACS	Alaska Clean Seas
ADEC	Alaska Department of Environmental Conservation
ADF&G	Alaska Department of Fish & Game
ADNR	Alaska Department of Natural Resources
AE	acoustic emissions
Alyeska	Alyeska Pipeline Service Company
ANSI	American National Standards Institute
AOGCC	Alaska Oil and Gas Conservation Commission
API	American Petroleum Institute
ARRT	Alaska Regional Response Team
ASME	American Society of Mechanical Engineers
ATV	all-terrain vehicle
BAT	best available technology
bbl	barrels
BGP	below-grade piping
BLM	Bureau of Land Management
BOP	blowout preventer
bopd	barrels of oil per day
boph	barrels of oil per hour
bpd	barrels per day
bph	barrels per hour
BPXA	BP Exploration (Alaska) Inc.
BSEE	Bureau of Safety and Environmental Enforcement
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act
CHD	closed hydrocarbon drain
CP	cathodic protection
CO_2	carbon dioxide
CPAI	ConocoPhillips Alaska, Inc.
CPF	Central Production Facility
CPM	computational pipeline monitoring
cu yd	cubic yards
DOT	U.S. Department of Transportation
DP	differential pressure
DS	drill site

EMOC	Emergency Operations Center
ENI	ENI Petroleum
EOR	enhanced oil recovery
EPA	U.S. Environmental Protection Agency
ERD	extended reach drilling
ESD	emergency shutdown
ESI	Environmental Sensitivity Index
FBE	fusion bonded epoxy
FEC	Field Environmental Compliance
FLIR	Forward-Looking Infrared System
FOSC	Federal On-Scene Coordinator
FRT	Field Response Team
ft	feet
GOR	gas-to-oil ratio
gpm	gallons per minute
H_2S	hydrogen sulfide
HAZMAT	Hazardous Materials
HAZWOPER	Hazardous Waste Operations and Emergency Response
HDPE	high density polyethylene
HMRT	hazardous materials response team
HSE	Health, Safety & Environment
IARC	International Agency for Research on Cancer
ICP	Incident Command Post
ICS	Incident Command System
IMAT	Incident Management Assist Team
IMT	Incident Management Team
KIC	Kuparuk Industrial Center
KRU	Kuparuk River Unit
Kuparuk Pipeline	Kuparuk Crude Oil Transmission Pipeline
KUTP	Kuparuk Unit Topping Plant
LEPC	Local Emergency and Planning Committee
MAD	Mutual Aid Drill
MB	Mass Balance
MBLPC	Mass Balance Line Pack Compensation
MI	miscible injectant
mm	millimeter
mmscfd	million standard cubic feet per day
mph	miles per hour
MWAG	miscible water alternating gas
NACE	National Association of Corrosion Engineers
NCP	National Contingency Plan
NGL	natural gas liquid

NPDES	National Pollutant Discharge Elimination System
NPRA	National Petroleum Preserve – Alaska
NPREP	National Preparedness for Response Exercise Program
NPWM	negative pressure wave monitoring
NRC	National Response Center
NSB	North Slope Borough
NSRRT	North Slope Regional Response Team
NSSRT	North Slope Spill Response Team
NTP	National Toxicology Program
ODPCP	Oil Discharge Prevention and Contingency Plan
OPA 90	Oil Pollution Act of 1990
ORLTA	oil resistant low temperature
OSHA	Occupational Safety & Health Administration
OSRO	Oil Spill Removal Organization
PBU	Prudhoe Bay Unit
PEL	permissible exposure limit
PLC	programmable logic controller
PM	preventative maintenance
PPE	personal protective equipment
ppm	parts per million
psi	pounds per square inch
psig	pounds per square inch gauge
QI	Qualified Individual
RCRA	Resource Conservation and Recovery Act
ROV	remotely operated valve
ROW	right-of-way
RPS	response planning standard
RT	radiographic inspection
RTTM	real-time transient model
SCADA	supervisory control and data acquisition
SCAT	Shoreline Cleanup and Assessment Technique
scf	standard cubic feet
SOP	Standard Operating Procedure
SOSC	State On-Scene Coordinator
SPCC	spill prevention, control, and countermeasures
SPCO	State Pipeline Coordinator’s Office
SRT	Spill Response Team
STP	seawater treatment plant
TAPS	Trans Alaska Pipeline System
TF	Task Force
UHF	ultra high frequency
USCG	U.S. Coast Guard

USFWS	U.S. Fish and Wildlife Service
USGS	U.S. Geological Survey
UT	ultrasonic inspection
VHF	very high frequency
VSM	vertical support member
WCD	worst-case discharge

OIL POLLUTION ACT OF 1990 ADDENDUM

U.S. Department of Transportation (Revised July 2010) and U.S. Environmental Protection Agency

KUPARUK FIELD AND PIPELINE

OIL DISCHARGE PREVENTION AND CONTINGENCY PLAN

U.S. DEPARTMENT OF TRANSPORTATION

KUPARUK FIELD AND PIPELINE
OIL DISCHARGE PREVENTION AND CONTINGENCY PLAN
CROSS REFERENCE TO
U.S. DEPARTMENT OF TRANSPORTATION RESPONSE PLAN REQUIREMENTS

[49 CFR 194, SUBPART B]

REGULATION SECTION (49 CFR)	SECTION TITLE	PLAN SECTION
194.103	**Significant and substantial harm; operator's statement**	p. DOT - 11
(a)	Identification of line sections that might cause significant and substantial harm to the environment in the event of a discharge	OPA 90 Addendum, p. DOT-11, Section 3.1.3.
(b)	Response zone(s) considered to cause significant and substantial harm to the environment in the event of a discharge.	p. DOT - 11
(c)	Significant and substantial harm criteria.	p. DOT - 11
194.105	**Worst-case discharge**	
(a)	The worst-case discharge and the methodology, including calculations, used to arrive at the volume	OPA 90 Addendum, p. DOT-9
(b)(1)	Pipeline release WCD	p. DOT - 10
(b)(2)	Historical discharge WCD	p. DOT - 10
(b)(3)	Largest breakout tank WCD	p. DOT - 10
(b)(4)	Secondary containment prevention credits for breakout tank WCD.	p. DOT - 10
194.107	**General response plan requirements**	
(a)	Resources for responding, to the maximum extent practicable, to a worst-case discharge and to the substantial threat of such a discharge	OPA 90 Addendum, p. DOT-12, Sections 1.5; 1.6.3; 3.6
(b)	Certification that the response plan is consistent with the National Contingency Plan and applicable ACP.	OPA 90 Addendum, p. DOT-7
(c)(1)(i)	Information Summary as required by 194.113	OPA 90 Addendum, p. DOT-9
(c)(1)(ii)	Immediate notification procedures	Sections 1.1, 1.2, 3.3
(c)(1)(iii)	Spill detection and mitigation procedures	Sections 2.1, 2.5
(c)(1)(iv)	Name, address, telephone number of oil spill response organization	Section 3.8
(c)(1)(v)	Response activities and response resources	OPA 90 Addendum, p. DOT-12, Sections 1.1, 1.2, 1.5, 1.6, 3.3, 3.6, 3.8
(c)(1)(vi)	Names and telephone numbers of federal, state, and local agencies with pollution control responsibilities or support	Section 1.2; Tables 1-3, 1-4
(c)(1)(vii)	Training procedures	Sections 2.1.1, 3.9
(c)(1)(viii)	Equipment testing	Section 3.6.2
(c)(1)(ix)	Drill types, schedules, and procedures	Section 3.9

(c)(1)(x)	Plan review and update procedures	Introduction
(c)(2)	Response zone appendices	N/A, pipelines are entirely within a single response zone
(c)(3)	Description of response management organization, span of control, clear chain of command, and trained response personnel.	Section 3.3
194.113	**Information Summary**	
(a)(1)	Name and address of operator	OPA 90 Addendum, p. DOT-9
(a)(2)	Listing and description of response zones	OPA 90 Addendum, p. DOT-9
(b)(1)	The information for the core plan.	Refer to 194.107(c)(i) through 194.107(c)(x) in this cross-reference.
(b)(2)	Names or titles and 24-hour telephone numbers of the qualified individual(s) and at least one alternate.	p. DOT - 9
(b)(3)	Description of the response zone, including county(s) and state(s), for zones in which a WCD could cause substantial harm to the environment.	p. DOT - 9
(b)(4)	List of line sections for each pipeline contained in the response zone, identified by milepost or survey station number, or other operator designation.	p. DOT - 9
(b)(5)	The basis for the operator's determination of significant and substantial harm; and	p. DOT - 9
(b)(6)	The type of oil and volume of the WCD.	p. DOT - 12
194.115	**Response Resources**	
(a)	Identify and ensure, by contract or other approved means the resources necessary to remove, to the maximum extent practicable, a WCD and to mitigate or prevent a substantial threat of a WCD.	Section 1.5, Section 1.6, Section 3.8
(b)	Identify the response resources which are available to respond within the time specified, after discovery of a worst case discharge, or to mitigate the substantial threat of such a discharge as follows: Tier 1 – 12 hrs; Tier 2 – 36 hrs; and Tier 3 – 60 hrs.	Section 1.5, Section 1.6.
194.117	**Training**	
(a)(1)	All personnel know:	
(a)(1)(i)	Their responsibilities under the response plan,	Section 3.9
(a)(1)(ii)	Name and address of, and the procedure for contacting, the qualified individual on a 24-hour basis.	p. DOT-9, Section 1.2.1, Section 3.3, and Table 3-2
(a)(2)	Reporting personnel know:	
(a)(2)(i)	Content of the information summary of the response plan,	Section 3.9
(a)(2)(ii)	The toll-free number for the National Response Center,	Section 1.2, Section 3.9
(a)(2)(iii)	The notification process; and	Section 1.2, Section 3.9
(a)(3)	Personnel engaged in response activities know:	
(a)(3)(i)	Characteristics and hazards of the oil discharged,	Section 3.9, Section 3.10.1
(a)(3)(ii)	Conditions that are likely to worsen emergencies, including the consequences of facility malfunctions or failures, and the appropriate corrective action.	Section 3.4, Section 3.9

(a)(3)(iii)	Steps necessary to control any accidental discharge of oil and to minimize the potential for fire, explosion, toxicity, or environmental damage, and	Section 1.1, Section 1.3, Section 3.9
(a)(3)(iv)	Proper firefighting procedures and use of equipment, fire suits, and breathing apparatus.	Section 3.9.4
(b)	Maintain a training record for each individual that has been trained as required by this section and maintain the records in the following manner as long as the individual has responsibility under the response plan:	Section 3.9.5
(b)(1)	Records for operator personnel must be maintained at the operator's headquarters; and	Section 3.9.5
(b)(2)	Records for personnel engaged in response, other than operator personnel, shall be maintained as determined by the operator.	Section 3.9
(c)	Nothing in this section relieves the operator from the responsibility to ensure that all response personnel are trained to meet the OSHA standards for emergency response operations.	Section 3.9.1
195.440	**Public Awareness**	OPA 90 Addendum, p. DOT-10

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U.S. DEPARTMENT OF TRANSPORTATION CERTIFICATION OF PREPAREDNESS

CONOCOPHILLIPS ALASKA, INC.
KUPARUK FIELD AND CRUDE OIL TRANSMISSION PIPELINE

Pipeline Response Plans Officer
Pipeline and Hazardous Materials Safety Administration
U.S. Department of Transportation
P.O. Box 267
Alexandria, VA 22313-0267

ConocoPhillips Alaska, Inc. hereby certifies to the Pipeline and Hazardous Materials Safety Administration of the U.S. Department of Transportation that it has identified, and ensured by contract, or other means to be approved by the Pipeline and Hazardous Materials Safety Administration, the availability of private personnel and equipment to respond, to the maximum extent practicable, to a worst-case discharge or a substantial threat of such a discharge.

Tyrone Maxey
Manager, Greater Kuparuk Area Operations
ConocoPhillips Alaska, Inc.
Anchorage, Alaska

06/17/14
Date

This Certification of Response Preparedness was acknowledged before me on 6/17/2014, by Tyrone L. Maxey on behalf of said corporation.

LAURA E. MUTCH NOTARY PUBLIC STATE OF ALASKA

Laura E Mutch

My commission expires 4/18/2015

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AREA CONTINGENCY PLAN / NATIONAL CONTINGENCY PLAN CONSISTENCY CERTIFICATION

KUPARUK FIELD AND PIPELINE

ConocoPhillips Alaska, Inc. hereby certifies to the Pipeline and Hazardous Materials Safety Administration of the U.S. Department of Transportation that it has reviewed the National Contingency Plan (NCP) and applicable area contingency plans (ACP) and found the Oil Discharge Prevention and Contingency Plan for the Kuparuk Field and Pipeline to be consistent with them. The NCP/ACPs reviewed include the NCP as set forth in the 40 CFR Part 300 as published in FR Vol. 59, No. 178, Final Rule, September 15, 1994 and the *Alaska Federal/State Unified Preparedness Plan for Response to Oil & Hazardous Substance Discharges/Releases (*Unified Plan, January 2010*)*, Volume I and Volume II, *The Subarea Contingency Plans* (North Slope, May 2012).

Tyrone Maxey
Manager, Greater Kuparuk Area Operations

05/05/14
Date

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U.S. DEPARTMENT OF TRANSPORTATION INFORMATION SUMMARY

NAME AND ADDRESS OF OPERATOR

ConocoPhillips Alaska, Inc.
P.O. Box 100360
Anchorage, AK 99510-0360
Phone: (907) 276-1215

Street Address:
700 G Street
Anchorage, AK 99501-0360
Fax: (907) 265-6235

RESPONSE ZONE AND LINE DESCRIPTION

CPAI's Kuparuk Field consists of a single response zone containing the Kuparuk Crude Oil Transmission Pipeline (Kuparuk Pipeline). The Kuparuk Field is located on the North Slope, within the North Slope Borough, Alaska. The response zone includes the pipeline crossing of the Kuparuk River and adjacent wetlands.

NAME AND TELEPHONE NUMBER OF QUALIFIED INDIVIDUAL

Qualified Individual:

Manager, North Slope Integrated Operations & Projects
Bill Arnold or designee
(907) 659-7253 or (907) 263-4822

Alternate:

Manager, Greater Kuparuk Area Operations
Tyrone Maxey or designee
(907) 659-7219

CPAI Security maintains 24-hour contact numbers for the Qualified Individual and their alternates. Security can be reached in Anchorage at (907) 265-1000 or at Kuparuk at (907) 659-7300.

WORST-CASE DISCHARGE

In accordance with 49 CFR 194.105, the worst case discharge (WCD) is determined by calculating the WCD from pipelines, DOT-regulated breakout tanks, and consideration of maximum historical discharge. Consideration of the maximum historical discharge is not applicable. The calculation of the Kuparuk Pipeline and DOT-regulated WCD is as follows:

In accordance with 49 CFR 194.105(b)(1), the WCD for the pipeline is equal to the pipeline's maximum release time (RT_{max}) in hours plus the maximum shutdown response time (ST_{max}) in hours multiplied by the maximum flow rate (F_{max}) expressed in barrels per hour (bph) (based on maximum daily capacity of the pipeline), plus the largest pipeline drainage volume (PV_{max}) after shutdown of the line section(s) in the response zone expressed in barrels or:

$$WCD = [(RT_{max} + ST_{max}) * F_{max}] + PV_{max}$$

The Kuparuk Field has one pipeline subject to U.S. Department of Transportation WCD calculations: the 24-inch crude oil transmission line. Weather conditions do not affect the pipeline shutdown times (see calculation below).

CRUDE OIL TRANSMISSION PIPELINE

DESCRIPTION OF THE LINE SECTION

The Kuparuk Pipeline is approximately 36 miles in length, running between CPF-2 at Kuparuk Field and Trans Alaska Pipeline System (TAPS) Pump Station 1. The Kuparuk Pipeline crosses the Putuligayuk River northwest of Pump Station 1. There is a seasonal containment site located downriver from the pipeline crossing approximately 500 feet north of the Spine Road (Reference: Sheet 77, Alaska Clean Seas *Technical Manual*, Volume 2 Map Atlas).

BASIS OF DETERMINATION OF SIGNIFICANT AND SUBSTANTIAL HARM

As stated in 49 CFR.103(c), a line section can be expected to cause significant and substantial harm to the environment in the event of a discharge of oil into or on the navigable waters or adjoining shorelines if; the pipeline is greater than 6-5/8 inches in outside nominal diameter, greater than 10 miles in length, and the line section is located within a 1 mile radius of potentially affected environmentally sensitive areas, and could reasonably be expected to reach these areas.

The Kuparuk Pipeline has a nominal diameter greater than 6-5/8 inches and is 37 miles in length. In addition, the pipeline traverses tundra and crosses rivers.

Line segments are described in the ODPCP Table 2-5 and Section 3.1.3.

TYPE OF OIL AND VOLUME OF WORST-CASE DISCHARGE

RESOURCES TO RESPOND TO A WORST-CASE DISCHARGE

Sufficient resources are available to respond to a potential WCD or a threat of such a discharge. The WCD calculations are based on the longest portion (between valves) of the Kuparuk Pipeline, which is the

Information regarding specific tactics and equipment that would be utilized during a WCD is provided in the Alaska Clean Seas (ACS) *Technical Manual*, Volume 1, Tactics Descriptions. Off-pad spill response tactics are also detailed in Scenarios 1 through 3 in Section 1.6.3 of this plan. The scenarios include a production well blowout and a pipeline discharge to the Kuparuk River.

Section 1.1 of the ODPCP describes immediate response and notification actions, which include notification of ACS. The on-site personnel are the initial responders to spills at Kuparuk. SRT members will respond promptly upon notification. The estimated response time from discovery of a spill to the deployment of equipment varies depending on the location, pre-planning, logistical support, and available information. Initial SRT response along the Kuparuk pipeline route is within 2 hours. This section also contains additional information including seasonal transportation options.

Spill response equipment and supplies are available throughout the North Slope for immediate deployment. Equipment is pre-deployed at the CPFs, along the Kuparuk and Miluveach rivers, and on the

coastline. Special 40-foot-long “Spill Vans” at CPF-1 pad are equipped to respond to spills and can be rapidly deployed by towing on the Kuparuk road network. Off-road oil spill recovery operations can be conducted by Rolligons, Centaurs®, 6-wheelers, and 4-wheelers available to CPAI and ACS. Infrastructure and pre-staged equipment along the portion of pipeline subject to a potential WCD is illustrated in the ACS Technical Manual, Volume 2, Map Atlas Sheets 51, 52, 68, and 69. Boom is seasonally pre-deployed at the Kuparuk River.

Spill tracking equipment includes the Twin Otter, which is equipped with Forward-Looking Infrared System for aerial surveillance of released oil or temperature anomalies that could be indicative of a pipeline leak. Hand-held sensors are also available.

Waste disposal information is contained in the *Alaska Waste Disposal and Reuse Guide*. Released fluids can be recovered and transferred via vacuum truck or Rolligon with tanks to CPF-1 for recycling. Oiled gravel storage is located within the Kuparuk road system at DS 1-H. Temporary lined containment cells can be constructed at numerous locations. Temporary storage of oil, oily waste, and debris recovered during a spill cleanup is provided in Section 1.6.2.

CERTIFICATION OF RESPONSE PERSONNEL AND EQUIPMENT

Sufficient response personnel and equipment are available to respond to a WCD or threat of such a discharge. The information is provided in Sections 1.6.3, Spill Response Scenarios; 3.5, Logistical Support; 3.6, Response Equipment; and 3.8, Response Contractor Information.

PUBLIC AWARENESS

CPAI is committed to public safety and environmental protection and maintains a public awareness program for CPAI-operated DOT-regulated pipelines, in accordance with DOT regulations. CPAI periodically provides information to the public via the *Hazardous Liquids Pipeline Guide for Emergency and Public Officials* and related summary bulletins; a copy of the summary bulletin is provided on the following page.

SAFETY IS OUR TOP PRIORITY

IMPORTANT INFORMATION ABOUT PIPELINE SAFETY

ConocoPhillips Alaska Inc. is committed to the safe operation of the North Slope pipelines that it operates and is dedicated to the protection of its employees, the public, and the environment within the vicinity of the Alpine, Kuparuk, and Oliktok pipelines.

To enhance the continued safe operations of these pipelines, this general information is presented to increase pipeline safety awareness. If you require more specific information or have questions or concerns, please contact:

Alpine DOT Compliance Specialist **(907) 670-4224**
Kuparuk DOT Compliance Specialist **(907) 659-7574**

North Slope Transportation Pipelines

Pipelines remain the safest and most reliable method of transporting energy products from the production location to market and the consumer. ConocoPhillips Alaska, Inc. (ConocoPhillips) operates, for itself and on behalf of others, over 165 miles of transportation pipelines on the North Slope. Of these pipelines, approximately 130 miles are regulated by the U.S. Department of Transportation, Office of Pipeline Safety. These pipelines extend from the Alpine Facilities to the Trans Alaska Pipeline System.

The Alpine Oil Pipeline transports sales-quality crude oil from the Colville River Unit to the Kuparuk Pipeline at CPF2. The Kuparuk Pipeline transports Colville River Unit, Kuparuk River Unit, Milne Point Unit, and ENI sales quality crude to the Trans Alaska Pipeline System, connecting at Pump Station 1. A breakout tank is located at CPF2 to provide relief or storage during periods of pipeline upset, proration, or maintenance. The Alpine Arctic Heating Fuel Pipeline transports refined petroleum products and the Alpine Utility Pipeline transports treated seawater from CPF2 to the Alpine Facilities. The Oliktok Pipeline transports natural gas from the Prudhoe Bay Unit to CPF1. The Kuparuk and Oliktok Pipelines parallel the Spine Road for much of its route.

Potential Hazards

While rare, a leak from a transportation pipeline, depending on what the line is carrying at the time, could create breathing hazards for nearby habitants, start a fire or explosion, damage the environment, or injure plants and animals. A leak resulting in an explosion or a fire, inadvertently triggered by vehicles, equipment, or people, increases the risk of potential damage.

Preventive Measures

ConocoPhillips is responsible for the safe and efficient operations of its pipelines. State of the art operations control centers monitor and operate the pipeline systems. These control centers are manned 24 hours a day, 365 days a year, and are capable of shutting down the pipelines in case of an emergency.

In addition, to ensure the integrity of its pipelines, ConocoPhillips implements a variety of programs, procedures, and systems, including:

- Pipeline design, construction, operations, and maintenance in accordance with federal, state, and local codes, regulations, and statutes.
- Aggressive and proactive maintenance programs, including pipe inspection programs that utilize state-of- the-art tools.
- Automated computer-based around-the-clock pipeline monitoring.
- Routine air and/or ground surveillance.
- Checkpoints along the pipeline route to enhance security when required.

Pipeline Signage

To enhance the identification of the transportation pipelines and provide emergency contact information, signage is attached to the North Slope transmission pipelines.

Pipeline signage provides important safety information and it is a *federal crime* for any person to willfully deface, damage, remove, or destroy any pipeline sign or right-of-way marker required by federal law. The penalty for each offense is a fine of up to $5,000, imprisonment for not more than one year, or both.

Example of Pipeline Signage

To Ensure Your Safety

To help ensure your safety and prevent pipeline damage, please ***do not***:

- Operate equipment near pipelines without permission.
- Dig near pipelines without permission.
- Shoot in the direction of the pipelines.
- Climb, walk on, or tie anything to the pipelines.

If you observe any unusual activities taking place near the pipelines, please contact ConocoPhillips immediately at the telephone numbers shown below in the section titled "In Case of an Emergency, call". Pipeline damage caused by these activities may result in *fines or penalties* to those causing the damage.

How to Recognize a Leak

By Sight: A pipeline product on the ground near a pipeline, a dense white cloud or fog over a pipeline, or discolored vegetation surrounding the pipeline may be signs of a leak.

By Sound: An unusual noise coming from the pipeline. A hissing or roaring sound may be a sign of a leak.

By Smell: An unusual odor may accompany a pipeline leak (e.g., pungent hydrocarbon, kerosene, gasoline-like, etc.).

If You Suspect or Discover a Leak

- Do not touch, breathe, or make contact with leaking liquids.
- Do not light a match, start an engine, use a telephone or cell phone, switch on/off light switches, or do anything that may create a spark.
- Do not drive into a leak or vapor cloud area.
- Turn off running motors or other ignition sources.
- Immediately leave the area in an upwind direction.
- Warn others!
- From a safe location, call ConocoPhillips as soon as possible at the telephone numbers shown below in the section titled "In Case of an Emergency, call". Please provide your name, phone number, a description of the leak or spill and its location.
- Contact the Nuiqsut Public Safety Department and Fire Department at the telephone numbers shown below in the section titled "In Case of an Emergency, call".

Figure 1 - Transportation Pipelines Route

What Happens when You Report a Leak or Unusual Activity

If a leak is reported, ConocoPhillips will take immediate action to stop the leak and contain and clean up the spill in accordance with approved Discharge Response and Contingency Plans. Such a response includes notification of the appropriate federal, state, and local authorities.

If an unusual activity near the pipelines is reported, ConocoPhillips will immediately investigate the situation and take action as appropriate.

For More Information

- ConocoPhillips Alaska, Inc.
  P.O. Box 196105
  Anchorage, AK 99519-6105
  (907) 276-1215
- Pipeline Safety Information
  http://primis.phmsa.dot.gov/comm/Index.htm
  Website provides stakeholder communications to facilitate pipeline safety.
- National Pipeline Mapping System
  http://www.npms.phmsa.dot.gov/
  Website provides maps within a specific zip code and information regarding the product transported and identification of the pipeline operator.

In Case of an Emergency, call

ConocoPhillips Alaska, Inc.

- ALPINE (907) 670-4900 or 911
- KUPARUK (907) 659-7300 or 911

COLLECT CALLS WILL BE ACCEPTED

Village of Nuiqsut

- PUBLIC SAFETY (907) 480-6911
- FIRE DEPARTMENT 911

If traveling through the Kuparuk field, you may chose to report leaks or other safety concerns at the Seawater Treatment Plant (STP), CPF2, CPF3, or the Kuparuk Office Complex (KOC).

U.S. ENVIRONMENTAL PROTECTION AGENCY

KUPARUK FIELD AND PIPELINE
OIL DISCHARGE PREVENTION AND CONTINGENCY PLAN

U.S. ENVIRONMENTAL PROTECTION AGENCY
CROSS REFERENCE

[40 CFR 112, APPENDIX F]

REGULATION SECTION (APPENDIX F)	SECTION TITLE	PLAN SECTION
1.1	**Emergency Response Action Plan [112.20(h)(1)]**	
1.1.1	Qualified Individual Information	OPA 90 Addendum, p. EPA-7
1.1.2	Emergency Notification Phone List	Section 1.2, Table 1-3
1.1.3	Spill Response Notification Form	Section 1.2.1, Figure 1-1
1.1.4	Response Equipment List and Location	Section 3.6
1.1.5	Response Equipment Testing and Deployment	Section 1.5 and 3.6
1.1.6	Facility Response Team	Section 1.2
1.1.7	Evacuation Plan	Section 1.3
1.1.8	Immediate Actions	Section 1.1
1.1.9	Facility Diagram	Section 1.8
1.2	**Facility Information [112.20(h)(2)]**	
1.2.1	Facility Name and Location	OPA 90 Addendum, pp. EPA-3 and EPA-7
1.2.2	Latitude and Longitude	OPA 90 Addendum, pp. EPA-3 and EPA-7
1.2.3	Wellhead Protection Area	OPA 90 Addendum, p. EPA-7
1.2.4	Owner/Operator	OPA 90 Addendum, p. EPA-7
1.2.5	Qualified Individual	OPA 90 Addendum, p. EPA-7
1.2.6	Date of Oil Storage Start-up	OPA 90 Addendum, p. EPA-7
1.2.7	Current Operation	Section 3.1
1.2.8	Dates and Type of Substantial Expansion	OPA 90 Addendum, pp. EPA-7 and EPA-8
1.3	**Emergency Response Information [112.20(h)(3)]**	
1.3.1	Notification	Sections 1.2 and 3.3
1.3.2	Response Equipment List	Section 3.6.1
1.3.3	Response Equipment Testing/Deployment	Sections 1.5 and 3.6
1.3.4	Personnel	Sections 1.5, 3.3, and 3.8
1.3.5	Evacuation Plans	Section 1.3
1.3.6	Qualified Individual's Duties	Section 1.2 and 3.3

U.S. ENVIRONMENTAL PROTECTION AGENCY
CROSS REFERENCE (CONTINUED)
[40 CFR 112, APPENDIX F]

REGULATION SECTION (APPENDIX F)	SECTION TITLE	PLAN SECTION
1.4	**Hazard Evaluation [112.20(h)(4)]**	
1.4.1	Hazard Identification	Sections 2.1.7, 2.1.8, 2.1.9, 2.3, and 2.4; Kuparuk SPCC Plan
1.4.2	Vulnerability Analysis	Section 3.10
1.4.3	Analysis of the Potential for an Oil Spill	Sections 2.3 and 2.4
1.4.4	Facility Reportable Oil Spill History	Section 2.2 and Table C-2
1.5	**Discharge Scenarios [112.20(h)(5)]**	
1.5.1	Small and Medium Discharges	Section 1.6.3
1.5.2	Worst-Case Discharge	OPA 90 Addendum, p. EPA-8, Section 1.6.3
1.6	**Discharge Detection Systems [112.20(h)(6)]**	
1.6.1	Discharge Detection by Personnel	Section 2.5
1.6.2	Automated Discharge Detection	Section 2.5
1.7	**Plan Implementation [112.20(h)(7)]**	
1.7.1	Response Resources for Small, Medium and Worst-Case Spills	Sections 1.5, 1.6.3, 3.3, 3.5, 3.6, 3.7, 3.8
1.7.2	Disposal Plans	Section 1.6.2
1.7.3	Containment and Drainage Planning	Sections 1.6.3, 2.1.9, and 3.1
1.8	**Self Inspection, Drills/Exercises, and Response Training [112.20(h)(8)]**	
1.8.1	Facility Self-Inspection	Sections 2.1.6, 2.1.7, 2.1.9, and 3.1
1.8.1.1	Tank Inspection	Sections 2.1.8
1.8.1.2	Response Equipment Inspection	Section 3.6.2
1.8.1.3	Secondary Containment Inspection	Section 2.1.9
1.8.2	Facility Drills/Exercises	Sections 3.9
1.8.2.1	Qualified Individual Notification Drill Logs	Sections 3.9; Facility Records
1.8.2.2	Spill Management Team Tabletop Exercise Logs	Sections 3.9; Facility Records
1.8.3	Response Training	Sections 2.1.1 and 3.9
1.9	**Diagrams [112.20(h)(9)]**	**Section 1.8**
1.10	**Security [112.20(h)(10)]**	**Sections 2.1.4**
2	**Response Plan Cover Sheet [112.20(h)(11)]**	**OPA 90 Addendum, p. EPA-3**
2.1	**General Information**	**OPA 90 Addendum, p. EPA-3**
2.2	**Applicability of Substantial Harm Criteria**	**OPA 90 Addendum, p. EPA-4**
2.3	**Certification**	**OPA 90 Addendum, p. EPA-5**
3.0	**Acronyms**	**p. TOC-9**

U.S. EPA RESPONSE PLAN COVER SHEET

GENERAL INFORMATION

Owner/Operator of Facility: ConocoPhillips Alaska, Inc.

Facility Name: Kuparuk Field and Kuparuk Pipeline

Facility Address (street address or route): P.O. Box 196105 (Mailing address)

The Kuparuk Field and Kuparuk Pipeline are located on the North Slope of Alaska.

City, State, and U.S. Zip Code: Anchorage, AK 99519-6105 (Mailing address)

Facility Phone No.: (907) 659-7242

Latitude (Degrees: North):

Longitude (Degrees: West):

Dun & Bradstreet Number: 048422034

Standard Industrial Classification (SIC) Code: 1330

Largest Above-Ground Oil Storage Tank Capacity (Gallons)

Maximum Oil Storage Capacity (Gallons):

Number of Above-Ground Oil Storage Tanks: 38

Worst-Case Oil Discharge Amount (Gallons):

Facility Distance to Navigable Water (Mark the appropriate line):

0-1/4 mile	1/4-1/2 mile	1/2-1 mile	>1 mile
X			

U.S. EPA RESPONSE PLAN COVER SHEET

Page 2 of 3

APPLICABILITY OF SUBSTANTIAL HARM CRITERIA

Facility Name: Kuparuk Field and Kuparuk Pipeline

Does the facility transfer oil over water to or from vessels and does the facility have a total oil storage capacity greater than or equal to 42,000 gallons?

Yes _____

No X

Does the facility have a total oil storage capacity greater than or equal to 1 million gallons and does the facility lack secondary containment that is sufficiently large to contain the capacity of the largest above-ground oil storage tank plus sufficient freeboard to allow for precipitation within any above-ground oil storage tank area?

Yes _____

No X

Does the facility have a total oil storage capacity greater than or equal to 1 million gallons and is the facility located at a distance (as calculated using the appropriate formula in Appendix C or a comparable formula) such that a discharge from the facility could cause injury to fish and wildlife and sensitive environments?

Yes X

No _____

Does the facility have a total oil storage capacity greater than or equal to 1 million gallons and is the facility located at a distance (as calculated using the appropriate formula in Appendix C or a comparable formula) such that a discharge from the facility would shut down a public drinking water intake?

Yes _____

No X

Does the facility have a total oil storage capacity greater than or equal to 1 million gallons and has the facility experienced a reportable oil spill in an amount greater than or equal to 10,000 gallons within the last 5 years?

Yes X

No _____

U.S. EPA RESPONSE PLAN COVER SHEET

Page 3 of 3

CERTIFICATION

I certify under penalty of law that I have personally examined and am familiar with the information submitted in this document, and that based on my inquiry of those individuals responsible for obtaining information, I believe that the submitted information is true, accurate, and complete.

Signature: _____

Name (Please type or print): Tyrone Maxey

Title: Manager, Greater Kuparuk Area Operations

Date: 05/05/14

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U.S. EPA RESPONSE PLAN FACILITY INFORMATION FORM

Facility Name: Kuparuk Field and Kuparuk Pipeline

Location (Street Address): The Kuparuk Field and Kuparuk Pipeline are located on the North Slope of Alaska.

City: N/A

State: Alaska Zip: N/A

County: N/A Phone Number: (907) 659-7242

Latitude:

Longitude

Wellhead Protection Area: N/A

Owner: ConocoPhillips Alaska Inc.

Owner Location (Street Address): 700 G Street

P.O. Box 100360 (mailing address)

(if different from Facility Address)

City: Anchorage

State: Alaska Zip: 99510-0360

County: N/A Phone Number: (907) 276-1215

Operator (if not Owner): ConocoPhillips Alaska, Inc.

Qualified Individual(s): (attach additional sheets if more than one)

Name: Bill Arnold

Position: Manager, North Slope Integrated Operations & Projects

Work Address: P.O. Box 100360, Anchorage, AK 99510-0360

Home Address: Anchorage, Alaska

Emergency Phone Number: (907) 659-7253 or (907) 263-4822

Date of Oil Storage Start-up: 1981

Current Operations: Active Production

Standard Industrial Classification: 1330

Date(s) and Types(s) of Substantial Expansion(s): See Section 3.1

1984: NGL plant was added to CPF-1; CPF-2 began operation; 24-inch oil crude oil transmission pipeline replaced 16-inch line; 16-inch oil sales pipeline converted to gas line.

1986: CPF-3 began operation.

1995: 16-inch sales gas export pipeline converted to NGL import service

1998: Tarn project with two additional drill sites, began production.

U.S. EPA RESPONSE PLAN FACILITY INFORMATION FORM (CONT.)

Date(s) and Types(s) of Substantial Expansion(s) Continued:

2000: Alpine crude metering and custody transfer modules, transfer pumps and diesel pumps added at CPF-2.

2001: Meltwater Development Project on-line.

2001: Drill site 3S Development, including gravel pad, pipeline, and gravel road.

2014: 16-inch Oliktok Pipeline converted from NGL to fuel gas.

WORST-CASE DISCHARGE

Type of Oil and Volume of Worst-Case Discharge

Using the calculation described in 40 CFR 112, Appendix D, Part B.2, the WCD is equal to the capacity of the largest single aboveground oil storage tank within an adequate secondary containment area, plus the volume of all aboveground tanks without adequate secondary containment, plus the production volume of the well with the highest output.

In 2011, the Kuparuk well with the highest production rate was 1J-166 at 1,437 bopd. However it should be noted that this well produces heavy oil and is on gas lift assistance aided by heat trace (see discussion in Section 5.1). Without gas lift and heat trace, it is unlikely this well would flow to the surface for a prolonged period of time.

Worst Case Discharge Calculations

**Rate of recovery is based on liquid recovery rate demonstrated in the summer well blowout scenario in Section 1.6.3; however, additional liquid recovery equipment is available through Alaska Clean Seas, which would increase the rate, if necessary.

BASIS FOR DETERMINATION OF SIGNIFICANT AND SUBSTANTIAL HARM:

Operations in the Kuparuk Field and Pipeline have the potential to spill hydrocarbon material on tundra (wetlands) and into navigable waters of the United States. As such, it is determined to pose significant and substantial harm should a spill occur.

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Attachment E-1
Worksheet to Plan Volume of Response Resources for Worst Case Discharge – Petroleum Oils
Crude Oil WCD

Part I Background Information

Step (A) Calculate Worst Case Discharge in barrels (Appendix D)

(A)

Step (B) Oil Group[1] (Table 3 and section 1.2 of this appendix: 3

Step (C) Operating Area (choose one) . . . . ☒ Nearshore/Inland Great Lakes ☐ or Rivers and Canals

Step (D) Percentages of Oil (Table 2 of this appendix)

Percent Lost to Natural Dissipation	Percent Recovered Floating Oil	Percent Oil Onshore
30	50	50
(D1)	(D2)	(D3)

Step (E1) On-Water Oil Recovery: $\frac{\text{Step (D2) x Step (A)}}{100}$

Step (E2) Shoreline Recovery: $\frac{\text{Step (D3) x Step (A)}}{100}$

Step (F) Emulsification Factor (Table 3 of this appendix) 2.0

(F)

Step (G) On-Water Oil Recovery Resource Mobilization Factor (Table 4 of this appendix)

Tier 1	Tier 2	Tier 3
0.15	0.25	0.40
(G1)	(G2)	(G3)

[1] A facility that handles, stores, or transports multiple groups of oil must do separate calculations for each oil group on site except for those oil groups that constitute 10 percent of less by volume of the total oil storage capacity at the facility. For purposes of this calculation, the volumes of all products in an oil groups must be summed to determine the percentage of the facility's total oil storage capacity.

Attachment E-1 (Continued)
Worksheet to Plan Volume of Response Resources for Worst Case Discharge – Petroleum Oils
Crude Oil WCD

Part II On-Water Oil Recovery Capacity (barrels/day)

Part III Shoreline Cleanup Volume (barrels) . . . . . .

Part IV On-Water Response Capacity by Operating Area
(Table 5 of this appendix)
(Amount needed to be contracted for in barrels/day)

Tier 1	Tier 2	Tier 3

Part V On-Water Amount Needed to be Identified, but not Contracted for in Advance (barrels/day)

Tier 1	Tier 2	Tier 3

NOTE: To convert from barrels/day to gallons/day, multiply the quantities in Parts II through V by 42 gallons/barrel.

Attachment E-1
Worksheet to Plan Volume of Response Resources for Worst Case Discharge – Petroleum Oils
Crude Oil Divert Tank

Part I Background Information

Step (A) Calculate Worst Case Discharge in barrels (Appendix D)

Step (B) Oil Group[1] (Table 3 and section 1.2 of this appendix: 3

Step (C) Operating Area (choose one) . . . . ☒ Nearshore/Inland Great Lakes ☐ or Rivers and Canals

Step (D) Percentages of Oil (Table 2 of this appendix)

Percent Lost to Natural Dissipation	Percent Recovered Floating Oil	Percent Oil Onshore
30	50	50
(D1)	(D2)	(D3)

Step (E1) On-Water Oil Recovery $\frac{\text{Step (D2) x Step (A)}}{100}$

Step (E2) Shoreline Recovery $\frac{\text{Step (D3) x Step (A)}}{100}$ (E2)

Step (F) Emulsification Factor
(Table 3 of this appendix) 2.0
(F)

Step (G) On-Water Oil Recovery Resource Mobilization Factor
(Table 4 of this appendix)

Tier 1	Tier 2	Tier 3
0.15	0.25	0.40
(G1)	(G2)	(G3)

[1] A facility that handles, stores, or transports multiple groups of oil must do separate calculations for each oil group on site except for those oil groups that constitute 10 percent of less by volume of the total oil storage capacity at the facility. For purposes of this calculation, the volumes of all products in an oil groups must be summed to determine the percentage of the facility's total oil storage capacity.

Attachment E-1 (Continued)
Worksheet to Plan Volume of Response Resources for Worst Case Discharge – Petroleum Oils
Crude Oil Divert Tank

Part II On-Water Oil Recovery Capacity (barrels/day)

Tier 1	Tier 2	Tier 3

Part III Shoreline Cleanup Volume (barrels) . . . . . .

Part IV On-Water Response Capacity by Operating Area
(Table 5 of this appendix)
(Amount needed to be contracted for in barrels/day)

Tier 1	Tier 2	Tier 3

Part V On-Water Amount Needed to be Identified, but not Contracted for in Advance (barrels/day)

Tier 1	Tier 2	Tier 3

NOTE: To convert from barrels/day to gallons/day, multiply the quantities in Parts II through V by 42 gallons/barrel.

Attachment E-1
Worksheet to Plan Volume of Response Resources for Worst Case Discharge – Petroleum Oils
Ultra-Low Sulfur Diesel, Tank 19-504

Part I Background Information

Step (A) Calculate Worst Case Discharge in barrels (Appendix D)

(A)

Step (B) Oil Group[1] (Table 3 and section 1.2 of this appendix | 1

Step (C) Operating Area (choose one) . . . . ☒ Nearshore/Inland ☐ or Rivers and Great Lakes Canals

Step (D) Percentages of Oil (Table 2 of this appendix)

Percent Lost to Natural Dissipation	Percent Recovered Floating Oil	Percent Oil Onshore
80	20	10
(D1)	(D2)	(D3)

Step (E1) On-Water Oil Recovery $\frac{\text{Step (D2) x Step (A)}}{100}$

Step (E2) Shoreline Recovery $\frac{\text{Step (D3) x Step (A)}}{100}$

Step (F) Emulsification Factor
(Table 3 of this appendix) 1.0
(F)

Step (G) On-Water Oil Recovery Resource Mobilization Factor
(Table 4 of this appendix)

Tier 1	Tier 2	Tier 3
0.15	0.25	0.40
(G1)	(G2)	(G3)

[1] A facility that handles, stores, or transports multiple groups of oil must do separate calculations for each oil group on site except for those oil groups that constitute 10 percent of less by volume of the total oil storage capacity at the facility. For purposes of this calculation, the volumes of all products in an oil groups must be summed to determine the percentage of the facility's total oil storage capacity.

Attachment E-1 (Continued)
Worksheet to Plan Volume of Response Resources for Worst Case Discharge – Petroleum Oils
Ultra-Low Sulfur Diesel, Tank 19-504

Part II On-Water Oil Recovery Capacity (barrels/day)

Part III Shoreline Cleanup Volume (barrels) . . . . . .

Part IV On-Water Response Capacity by Operating Area
(Table 5 of this appendix)
(Amount needed to be contracted for in barrels/day)

Part V On-Water Amount Needed to be Identified, but not Contracted for in Advance (barrels/day)

Tier 1	Tier 2	Tier 3

NOTE: To convert from barrels/day to gallons/day, multiply the quantities in Parts II through V by 42 gallons/barrel.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 10
1200 Sixth Avenue, Suite 900
Seattle, Washington 98101-3140

September 24, 2012

Jeanie Shifflett
ConocoPhillips Alaska Inc.
P.O. Box 100360
Anchorage, AK. 99510-0036

RE: Review of Facility Response Plan FRPAKA0016, Kuparuk Facility

Ms. Shifflett:

Pursuant to the Clean Water Act, 33 U.S.C. Section 1321(j)(5), as amended by the Oil Pollution Act of 1990, the United States Environmental Protection Agency (U.S. EPA) has reviewed your Facility Response Plan (FRP) and finds that it meets the requirements of Section 311(j)(5) of the Clean Water Act and 40 CFR 112.20(c)(4). Your FRP is reapproved for 5 years until September 24, 2017.

Note that, pursuant to 40 CFR 112.20(d)(1), the owner or operator of a facility for which a response plan is required shall revise and resubmit revised portions of the response plan to U.S. EPA within 60 days of each facility change that may materially affect the response to a worst case discharge. Changes which may require revisions to a response plan include:

- a change in the facility's configuration;
- a change in the type of oil handled, stored or transferred;
- a change in the capabilities of the oil spill response organization;
- a change in the facility's spill prevention and response equipment or emergency response procedures; and
- any other change that materially affects the implementation of the response plan.

In addition, 40 CFR Section 112.20(d)(2) provides that changes in personnel and telephone number lists included in an FRP do not require U.S. EPA approval, but should be supplied to U.S. EPA as the revisions occur.

If you have questions regarding this correspondence, please contact me at 907-271-3247 or Janet Wien at 206-553-8634.

Sincerely,

Robert S. Whittier, Jr.
On Scene Coordinator (OSC)
Emergency Preparedness and Prevention Unit

REF: frp_5yearreview_approved

THE STATE of ALASKA
GOVERNOR SEAN PARNELL

Department of Environmental Conservation

DIVISION OF SPILL PREVENTION & RESPONSE
INDUSTRY PREPAREDNESS PROGRAM

555 Cordova Street
Anchorage, Alaska 99501
Main: 907.269.3094
Fax: 907.269.7687

March 7, 2013

File No.: 305.30
(CPAI Kuparuk)

OIL DISCHARGE PREVENTION AND CONTINGENCY PLAN APPROVAL

Jeanie Shifflett
Emergency Planning Coordinator
ConocoPhillips Alaska, Inc.
P.O. Box 100360
Anchorage, AK 99510-0360

Subject: **ConocoPhillips Alaska, Inc. Oil Discharge Prevention and Contingency Plan for Kuparuk River Unit – Kuparuk & Oliktok Pipelines, North Slope, Alaska: Plan Number 12-CP-4102. Plan Approval**

Dear Ms. Shifflett:

The Alaska Department of Environmental Conservation (department) has completed our review of your renewal application for the above-referenced Oil Discharge Prevention and Contingency Plan (plan) dated November 2012. The department coordinated the State of Alaska's public review for compliance with 18 AAC 75, using the review procedures at 18 AAC 75.455. Based on our review, the department has determined that your plan is consistent with the applicable requirements of the regulations and is hereby approved.

This approval applies to the following plan:

Plan Title:	**ConocoPhillips Alaska, Inc., Oil Discharge Prevention and Contingency Plan for Kuparuk River Unit – Kuparuk & Oliktok Pipelines, North Slope, Alaska**
Supporting Documents:	**Alaska Clean Seas Technical Manual, as revised and updated**
Plan Holder:	**ConocoPhillips Alaska, Inc.** **P. O. Box 100360** **Anchorage, AK 99510-0360**
Covered Facilities:	**Kuparuk River Unit production facilities and the associated flow lines; Kuparuk crude oil transmission pipeline, Oliktok Pipeline, drill sites, tanks, and other production operations.**

PLAN APPROVAL: Approval of the referenced plan is hereby granted **effective March 7, 2013.** This approval supersedes all previous plan approvals. A Certificate of Approval stating that the department has approved the plan is enclosed. This approval is subject to the following terms and conditions.

TERMS AND CONDITIONS

The following items must be completed and/or received as specified to complete the plan in accordance with AS 46.04.030(e) and 18 AAC 75.460(a).

1. **Notice of Changed Relationship with Response Action Contractor:** Because the plan relies on the use of response contractors for its implementation, ConocoPhillips Alaska, Inc. (CPAI) must immediately notify us in writing of any change in the contractual relationship with the plan holder's response action contractor, and of any event including but not limited to any breach by either party to the response contract that may excuse a response contractor from performing, that indicates a response contractor may fail or refuse to perform, or that may otherwise affect the response, prevention, or preparedness capabilities described in the approved plan.

   This condition is reasonable and necessary because there are certain risks associated with allowing a plan holder to rely in part or total upon a response contractor instead of obtaining its own response capability. The risks arise, in part, because the certainty of the contractor's response is dependent upon the continuation of the legal relationship between the contractor and the plan holder. Given this risk, the department must be promptly informed of any change of the contractual relationship between the plan holder and the response contractor, and of any other event that may arguably excuse the response contractor from performing or that would otherwise affect the response, prevention, or preparedness capabilities described in the approved plan. The department may seek appropriate modifications to the plan or take other steps to ensure that the plan holder has continuous access to sufficient resources to protect the environment and to contain, clean up, and mitigate potential oil spills. 18 AAC 75.425(e)(3)(H) and 18 AAC 75.445(i)

2. **Blowout Contingency Plan:** A copy of the Blowout Contingency Plan (BCP) must be maintained at Kuparuk River Unit and made available to the department upon request. A copy of the BCP must be made available for review by the Alaska Oil and Gas Conservation Commission upon its or the department's request.

   This condition is reasonable and necessary to ensure that the plan holder is prepared to control a potential well blowout. 18 AAC 75.425(e)(1)(I), 18 AAC.445(d)(2), and 18 AAC 75.480

3. **Crude Oil Transmission Pipeline Leak Detection:** CPAI is currently switching its main electronic leak detection system from the EFA Technologies, Inc. LeakNet system to the LineGuard system. Current language in the plan states that the LineGuard system is already in use. CPAI must amend the plan upon receipt of this approval to reflect the LeakNet system in Section 2.5.2 as currently in use. The amendment application must be submitted in accordance with 18 AAC 75.415 within 15 days of this letter. Once software packages are installed and final calibrations are completed, the department must be notified and CPAI must submit an amendment to the plan identifying the LineGuard system as being in use.

   This condition is reasonable and necessary to ensure that the plan accurately describes the crude oil transmission pipeline leak detection system required by 18 AAC 75.055(a) in accordance with 18 AAC 75.425(e)(2)(E) and 18 AAC.445(m).

4. **Final Copy of the Plan:** Within 30 days of this letter, the plan holder must submit to the department updated versions of the approved plan, including all revisions instituted during the recent plan review. CPAI must send three complete plan copies to the Exploration, Production & Refineries Section in Anchorage. In addition, you must send an updated version of the plan to each reviewer and controlled document holder of your plan.

EXPIRATION: This approval **expires March 7, 2018.** After the approval expires, Alaska law prohibits operation of the facility until an approved plan is once again in effect.

AMENDMENT: Except for routine updates under 18 AAC 75.415(b), before a change to this plan may take effect, the plan holder must submit an Application for Amendment to the plan with any additional information needed to evaluate the proposed amendment. This is to ensure that changes to the plan do not diminish the plan holder's ability to respond to a discharge and to evaluate any additional environmental considerations that may need to be taken into account (18 AAC 75.415).

RENEWAL: To renew this approval, the plan holder must submit a completed renewal application and plan to the department no later than 180 days prior to the expiration of this approval. This is to ensure that the submitted plan is approved before the current plan in effect expires (18 AAC 75.420)

REVOCATION, SUSPENSION, OR MODIFICATION: This approval is effective only while the plan holder is in "compliance with the plan" and with all of the terms and conditions described above. The department may, after notice and opportunity for a hearing, revoke, suspend, or require the modification of an approved plan if the plan holder is not in compliance with it, or for any other reason stated in AS 46.04.030(f). In addition, Alaska law provides that a vessel or facility that is not in "compliance with the plan" may not operate (AS 46.04.030). The department may terminate approval prior to the expiration date if deficiencies are identified that would adversely affect spill prevention, response, or preparedness capabilities.

DUTY TO RESPOND: Notwithstanding any other provisions or requirements of this plan, a person causing or permitting the discharge of oil is required by law to immediately contain and cleanup the discharge regardless of the adequacy or inadequacy of a plan (AS 46.04.020).

NOTIFICATION OF NON-READINESS: Within twenty-four (24) hours after any significant response equipment specified in the plan becomes non-operational or is removed from its designated storage location, the plan holder must notify the department in writing and provide a schedule for the equipment's substitution, repair, or return to service (18 AAC 75.475[b]).

CIVIL AND CRIMINAL SANCTIONS: Failure to comply with the plan may subject the plan holder to civil liability for damages and to civil and criminal penalties. Civil and criminal sanctions may also be imposed for any violation of AS 46.04, any regulation issued there under, or any violation of a lawful order of the department.

INSPECTIONS, DRILLS, RIGHTS TO ACCESS, AND VERIFICATION OF EQUIPMENT, SUPPLIES, AND PERSONNEL: The department has the right to verify the ability of the plan holder to carry out the provisions of its plan and access to inventories of equipment, supplies, and personnel through such means as inspections and discharge exercises,

without prior notice to the plan holder. The department has the right to enter and inspect the covered vessel or facility in a safe manner at any reasonable time for these purposes and to otherwise ensure compliance with the plan and the terms and conditions (AS 46.04.030[e] and AS 46.04.060). The plan holder shall conduct exercises for the purpose of testing the adequacy of the plan and its implementation (18 AAC 75.480 and 485).

FAILURE TO PERFORM: In granting approval of the plan, the department has determined that the plan, as represented to the department by the applicant in the plan and application for approval, satisfies the minimum planning standards and other requirements established by applicable statutes and regulations, taking as true all information provided by the applicant. The department does not warrant to the applicant, the plan holder, or any other person or entity: (1) the accuracy or validity of the information or assurances relied upon; (2) that the plan is or will be implemented; or (3) that even full compliance and implementation with the plan will result in complete containment, control, or cleanup of any given oil spill, including a spill specifically described in the planning standards. The plan holder is encouraged to take any additional precautions and obtain any additional response capability it deems appropriate to further guard against the risk of oil spills and to enhance its ability to comply with its duty under AS 46.04.020(a) to immediately contain and clean up an oil discharge.

COMPLIANCE WITH APPLICABLE LAWS: If amendments to the approved plan are necessary to meet the requirements of any new laws or regulations, the plan holder must submit an application for amendment to the department at the above address. The plan holder must adhere to all applicable state statutes and regulations as they may be amended from time to time. This approval does not relieve the plan holder of the responsibility for securing other federal, state, or local approvals or permits, and the plan holder is still required to comply with all other applicable laws.

INFORMAL REVIEW OR ADJUDICATORY HEARING: Any person who disagrees with this decision may request an adjudicatory hearing in accordance with 18 AAC 15.195 - 18 AAC 15.340 or an informal review by the Division Director in accordance with 18 AAC 15.185.

Informal review requests must be delivered to the Division Director, 410 Willoughby Avenue, Suite 303, PO Box 111800, Juneau, Alaska 99811-1800 within 15 days of the permit decision.

Adjudicatory hearing requests must be delivered to the Commissioner of the Department of Environmental Conservation, 410 Willoughby Avenue, Suite 303, PO Box 111800, Juneau, Alaska 99811-1800, within 30 days of the permit decision. If a hearing is not requested within 30 days, the right to appeal is waived. Anyone who submits a request for an informal review or an adjudicatory hearing should also send a copy of the request to the undersigned.

If you have any questions, please contact Gary Evans at 269-7536 or at gary.evans@alaska.gov.

Sincerely,

Betty Schorr

Betty Schorr
Program Manager

Attachment: Summary of Basis for Department Decision

Enclosure: Certificate of Approval number 13CER-013

Electronic cc w/o Enclosure:

Graham Wood, ADEC
Gary Evans, ADEC
Tom DeRuyter, ADEC
Ashley Anderson, ADEC
DNR C-Plan, ADNR
Gordon Brower, NSB
Rhoda Ahmaogak, NSB
Hon. Charlotte Brower, NSB
Jake Adams, NSB
Richard Camilleri, NSB
Tony Cabinboy, NSB
John Boyle III, NSB
Jack Winters, ADFG
Matt Carr, USEPA
Melanie Barber, USDOT
Mike Thompson, JPO
Pam Miller, Northern Alaska Environmental Center
Susan Harvey, Harvey Consulting
Legal Director, Trustees for Alaska
LCDR Daniel Buchsbaum, USCG Sector – Anchorage

ALASKA DEPARTMENT
of
Environmental Conservation
Certificate of Approval
for
Oil Discharge Prevention and Contingency Plan

Certificate Number: **13CER-013**

Plan Number: **12-CP-4102**

Name of Plan:	**ConocoPhillips Alaska, Inc., Oil Discharge Prevention and Contingency Plan for Kuparuk River Unit – Kuparuk & Oliktok Pipelines, North Slope, Alaska**
Covered Facilities:	**Kuparuk River Unit production facilities and the associated flow lines; Kuparuk crude oil transmission pipeline, Oliktok Pipeline, drill sites, tanks, and other production operations.**
Address:	**ConocoPhillips Alaska, Inc.** **P. O. Box 100360** **Anchorage, AK 99510-0360**
Telephone:	**(907) 276-1215** Fax: **(907) 265-6216**

Region of Operation (18 AAC 75.495): **North Slope, Alaska**

Effective Date of Approval: **March 7, 2013** Expiration Date: **March 7, 2018**

This approval is subject to the terms and conditions of the applicable Alaska Department of Environmental Conservation contingency plan approval letter and continuing compliance with the requirements of AS 46.04 and 18 AAC 75.

Betty Schorr 03-07-2013

Betty Schorr, Approving Authority **Date**
Program Manager, Industry Preparedness Program

PHMSA 00012849O

INTRODUCTION

This Oil Discharge Prevention and Contingency Plan (ODPCP) is for the Kuparuk Field and Kuparuk Crude Oil Transmission Pipeline (Kuparuk Pipeline) located within the North Slope Borough, Alaska. The Kuparuk Field facilities are owned by the Kuparuk River Unit (KRU). ConocoPhillips Alaska, Inc. (CPAI) is the operator of the facility covered by this plan. CPAI's address, phone, and fax numbers are provided below:

ConocoPhillips Alaska, Inc.
P.O. Box 100360
Anchorage, AK 99510-0360
Phone: (907) 276-1215

Street Address:
700 G Street
Anchorage, AK 99501-0360
Fax: (907) 265-6235

OBJECTIVES

The primary goal of an ODPCP is to prevent and plan for the response to a hydrocarbon or other fluid spill. In the event of a spill, the goals of this plan are to limit the spread of the spill, thereby minimizing potential environmental impacts, and to provide for the safety of personnel. Where the two may conflict, safety of personnel will always be given the first consideration.

This plan addresses requirements promulgated by the State of Alaska under Title 18, Chapter 75 of the Alaska Administrative Code (AAC), as amended through April 8, 2012. This plan also contains a section addressing federal regulations (U.S. Environmental Protection Agency [EPA] and U.S. Department of Transportation [DOT]) based on the Oil Pollution Act of 1990 (OPA 90).

The major facilities covered by this plan include:

- All phases of Kuparuk Field production facilities;
- Kuparuk Pipeline from CPF-2 to the Trans Alaska Pipeline System (TAPS) at Pump Station 1 at the flange upstream of the metering building.

CPAI assumes responsibility for containment and cleanup of all spills from its facilities and operations within the Kuparuk Field, including the Kuparuk Pipeline. CPAI does not assume responsibility for spills caused by others.

A spill response operation on the North Slope falls into one of three categories:

- **Level I:** Small operational spills dealt with by on-scene personnel and equipment.
- **Level II:** Larger spills that could affect the area around the facility or operation that require equipment and/or trained personnel located in the other operating areas of the North Slope.
- **Level III:** A major spill requiring resources from off the North Slope.

Both Level II and III spills may result in the activation of the Incident Management Team and/or the Crisis Response Team or Spill Response Team. As necessary, resources of other North Slope operators may be utilized through Alaska Clean Seas (ACS), Mutual Aid, and contractors. The response organization structure described in this plan is based on the Incident Command System and accommodates each level of response.

ACS TECHNICAL MANUAL

CPAI is a member of ACS, which serves as the primary response action contractor for CPAI operations on the North Slope. This ODPCP incorporates by reference, wherever applicable, the ACS *Technical Manual*, which consists of Volume 1, Tactics Descriptions, and Volume 2, Map Atlas. Volume 1 describes the tactics that can be used in responding to a variety of spill situations. Volume 2 provides maps and a narrative description of resources at risk and key response considerations.

PLAN CONTENTS ORGANIZATION

Following is a summary of the principal contents of this ODPCP:

- **Management Approval and Manpower Authorization.** The front matter of the ODPCP provides approval and authorization of resources as required to implement this plan.
- **OPA 90 Section.** This section addresses the federal spill planning regulations of the EPA (40 CFR 112), and DOT as applicable.
- **Part 1 – Response Action Plan.** The response action plan provides information to guide the Spill Response Team, Incident Management Team, and Crisis Response Team in a response to an incident. Information includes reporting and notification procedures, basic safety procedures, a communications plan, deployment and response strategies, and initial response procedures. Company personnel are familiar with the contents of this plan and other manuals necessary to carry out a successful response.
- **Part 2 – Prevention Plan**. The prevention plan provides a detailed description of policies, best management practices, and prevention measures employed on the North Slope. Information is included on identified risks, historical spills, and measures taken to minimize potential impacts.
- **Part 3 – Supplemental Information**. The supplemental information provides an overview of the facility operations, environmental information, and supporting response information.
- **Part 4 – Best Available Technology**. This section analyzes spill prevention and response equipment to ensure it meets performance standards in 18 AAC 75.
- **Part 5** – **Response Planning Standard.** This section presents a calculation of the applicable response planning standards and detailed basis for the calculation of reductions if applied to the response planning standard.

This ODPCP relies on information provided in the ACS *Technical Manual*, and that information is not repeated in this ODPCP. This ODPCP references specific tactics descriptions and maps contained in the ACS *Technical Manual*.

PLAN SUPPLEMENTAL DOCUMENTATION

The following table provides a listing of supplemental documents CPAI references for oil discharge prevention and response information.Key internal and external written materials are available at CPAI Emergency Operation Center facilities.

ODPCP Supplemental Documentation		
Document	**Author**	**Location/Link**
Alaska Administrative Code, Section 75 (18 AAC 75)	ADEC	http://dec.alaska.gov/commish/regulations/index.htm
Alaska Clean Seas Technical Manual, Volume 1, Tactical Descriptions; and, Volume 2, Map Atlas	Alaska Clean Seas	http://www.alaskacleanseas.org/tech-manual/.
Alaska Federal/State Preparedness Plan for Response to Oil & Hazardous Substance Discharges/Releases (Unified Plan)	Alaska Regional Response Team (ARRT)	http://dec.alaska.gov/spar/perp/plans/uc.htm
Alaska "Prevention and Emergency Response Subarea Plans Maps"	ADEC	http://www.asgdc.state.ak.us/maps/cplans/subareas.html#northslope.
Alaska Safety Handbook (ASH)	North Slope Operators	CPAI EOC facilities and CPAI internal internet Alaska North Slope HSE homepage.
CPAI Incident Management Handbook	CPAI	CPAI EOC facilities and CPAI internal internet Emergency Plans homepage.
CPAI Emergency Action Plans	CPAI	CPAI EOC facilities and CPAI internal internet Alaska North Slope HSE homepage.
CPAI Drilling and Wells Emergency Preparedness Blowout Contingency Plan	CPAI	CPAI EOC facilities and CPAI internal internet Emergency Plans homepage.
North Slope Environmental Field Handbook	CPAI	CPAI EOC facilities and CPAI internal internet Alaska North Slope HSE homepage.
NOAA Environmental Sensitivity Index (ESI) Maps.	NOAA	http://response.restoration.noaa.gov/esi.
North Slope Subarea Contingency Plan	ARRT	http://dec.alaska.gov/spar/perp/plans/scp_ns.htm.

PLAN DISTRIBUTION

The ODPCP is distributed to CPAI management and staff as appropriate. Agency personnel and external stakeholders are provided copies of the ODPCP, as appropriate.

UPDATING PROCEDURES

The ODPCP is revised and updated when major changes occur.

If it is determined that significant changes have occurred that would affect CPAI's ability to respond to a worst-case discharge (WCD), or would substantially affect the implementation of this plan, the ODPCP is updated or amended. Any significant amendment to the plan is submitted to the appropriate agency for review prior to implementation. Key factors that may cause revisions to the plan include:

- Modification of a CPAI operating area;
- Production facility modifications that create additional spill potential, affect the potential movement of spills, or alter proposed containment basins;
- Change in response procedures;
- Change in Oil Spill Removal Organization;
- Change in commodities transported;
- Organization or personnel changes;
- Changes in regulations promulgated by government agencies; or
- Improvements in state-of-the-art spill technology and equipment, and new equipment purchases.

Modifications to the plan may also occur after spill response drills or incidents have been fully evaluated. In addition, plan holders are encouraged to provide comments on the plan, which could lead to updates or modifications to the plan.

Revisions to the plan are logged on a Record of Revisions form. On receipt of revisions, the plan holder replaces pages as instructed and recorded on the Record of Revisions form provided in the front of the ODPCP. This process indicates the completeness of the plan, as revisions are consecutively numbered. It is the responsibility of each plan holder to ensure that updates are promptly incorporated into the plan.

PLAN RENEWAL

The ODPCP covers a number of state and federal approvals. CPAI ensures that plan renewals are submitted to the appropriate agencies according to their renewal timeframe. The approvals covered by this ODPCP and relevant renewal cycles are listed below:

REGULATING AGENCY	RENEWAL CYCLE	EXPIRATION DATE
Alaska Department of Environmental Conservation	5 years	March 7, 2018
U.S. Environmental Protection Agency	No more than every 5 years for facility response plan	September 24, 2017
U.S. Department of Transportation	5 years	March 7, 2018

The ODPCP will be submitted for renewal to all regulating agencies every 5 years, based on the Alaska Department of Environmental Conservation renewal schedule of every 5 years.

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PART 1 RESPONSE ACTION PLAN
[18 AAC 75.425(e)(1)]

1.1 EMERGENCY ACTION CHECKLIST [18 AAC 75.425(e)(1)(A)]

The person reporting an oil spill may be required to supply minimum spill assessment information to provide as complete an understanding of the event as possible. Table 1-1 and Table 1-2 provide some emergency actions and information that may be reported when a spill is first reported. Additional emergency action checklists are located in the *North Slope Environmental Field Handbook*.

TABLE 1-1:
EMERGENCY ACTION CHECKLIST

INITIAL SPILL RESPONSE ACTIONS	WHAT TO REPORT TO YOUR SUPERVISOR
1. Protect people. Safety is first priority. • Shut off ignition sources. • Restrict access. • Evaluate as necessary, and initiate rescue and response actions. 2. Notify Security and Supervisor. 3. Stop or contain the spill at source, if safe to do so. 4. Assess possible hazards: • Fire and explosion potential of vapors at or near the source, • Potential toxic effects of the discharge, • Damage to facility affecting safety, and • Recovery of the spilled product. 5. For a blowout, implement well control and evacuation procedures and activate Tier III Incident Command System (ICS).	1. Was anyone hurt? 2. Where is the spill? 3. What time did it happen? 4. What was spilled? 5. How much was spilled? 6. What is the rate of release? 7. What is the source? 8. What are the weather conditions? 9. What actions have you taken? 10. What equipment do you need? 11. Are there any immediate environmental impacts? 12. Who did you notify?

The emergency notification sequence varies depending on the size of the spill and required response. A minor spill defines a situation where the on-site employees are in control of the spill response and do not require immediate off-site assistance. A minor spill situation does not represent an emergency. Emergency situations exist where any of these conditions exist:

1. The safety of personnel is threatened.
2. The spilled material is of an unknown nature and is potentially hazardous or toxic.
3. The release of product cannot be quickly stopped or contained.

The levels described below apply only to the emergency phases of containment and initial recovery.

- **Minor.** Defines a situation where the on-site personnel can control the incident and Kuparuk Spill Response Team (SRT) response is not required.
- **Level I.** Defines a situation where the on-site employees require the assistance of the Kuparuk SRT and/or Hazardous Materials Response Team (HMRT) to control and contain a spill.

- **Level II.** Defines a situation that requires the assistance of the SRT and/or the HMRT (a Level I response), and other North Slope resources, including Alaska Clean Seas (ACS) and/or a request for Mutual Aid.
- **Level III.** Defines a situation that requires the activation of all North Slope resources and those available from sources other than North Slope suppliers. A Level III response would be activated in the event of a catastrophic spill.

TABLE 1-2:
EMERGENCY ACTION AND NOTIFICATION SEQUENCE

LEVEL I SPILL	
PERSONNEL	**ACTION TO BE TAKEN**
FIRST PERSON TO SEE THE SPILL	Assess safety of situation, determine whether source can be stopped, and stop the source of spill if possible. Immediately notify Security and Supervisor.
SECURITY	Record information about the spill on the spill report form from the spill observer or supervisor and request they stand by. Notify Environmental personnel. Implement Level I, II, or III Emergency Response Notification Plan (Figure 1-2).
NORTH SLOPE EMERGENCY RESPONSE CHIEF OR DEPUTY/ASSISTANT CHIEF	Assumes the role of initial Incident Commander. Coordinates with Support Groups responding to the emergency. Makes decision to evacuate the drill site, as necessary. Notifies area Production Superintendent. If pipeline spill, notifies Pipeline Coordinator.
FIELD ENVIRONMENTAL COORDINATOR	Notify the appropriate agencies according to the nature and circumstances of the spill. Ensure the Spill Report Form is completed by Responsible Party.

If the Emergency Response Chief or Deputy/Assistant Chief determines the spill is a Level II or III event, the following additional notifications should take place.

LEVEL II OR LEVEL III SPILL	
NORTH SLOPE EMERGENCY RESPONSE CHIEF DEPUTY/ASSISTANT CHIEF OR INCIDENT COMMANDER	Activate the CPAI Incident Management Team (IMT) and/or Mutual Aid, if required. Mobilize Forward Looking Infrared (FLIR) System.
IMT LIAISON OFFICER	Establish and maintain contact with the On-Scene Coordinator, the Regional Response Team (if activated), and other governmental agencies as necessary.

1.2 REPORTING AND NOTIFICATION [18 AAC 75.425(e)(1)(B)]

1.2.1 Initial Reporting [18 AAC 75.425(e)(1)(B)(i)]

Any person who causes or observes a spill will immediately report the spill to their supervisor. If their supervisor is not available, notify Security. Emergency contact phone numbers are listed in Table 1-3. A complete list of names and telephone numbers for persons responsible for making notifications is included in Table 3-2.

Once Security has been alerted, they will notify the appropriate response personnel depending on the spill size and safety issues involved (Figure 1-1). Security will activate a singular, all-call paging number to emergency responders. The emergency response notification plan is presented in Figure 1-2.

Security is available and maintains 24-hour contact phone numbers for personnel including the Qualified Individual (QI) who is the Manager, North Slope Operations, Alternate QI who is the Manager, Greater Kuparuk Area Operations, and ACS, the oil spill removal organization (OSRO). Contact information for the QI and the Alternate QI is contained in Section 3.3.

TABLE 1-3:
EMERGENCY CONTACT LIST

ConocoPhillips Alaska, Inc.

Kuparuk	Phone		Pager
Security	(907) 659-7997		
Emergency	(907) 659-7300 or 911		
Spill Response Team	(907) 659-7879		801
Health, Safety & Environment (HSE) Supervisor	(907) 659-7590		676
Manager, North Slope Operations	(907) 659-7253	OR	(907) 263-4822
Manager, Greater Kuparuk Area Operations	(907) 659-7219		851
Drilling Manager	(907) 265-6120		
Drilling Field Supervisor	(907) 659-7726		
Drilling Superintendent	(907) 265-1319		
Wells Manager	(907) 265-6306		
Wells Superintendent	(907) 659-7235		
Field Environmental Coordinator	(907) 659-7242		669
Emergency Response Chief	(907) 659-7494		400
Pipeline Coordinator	(907) 659-7574		467
Paging System	(907) 659-7000		
Kuparuk Medical Clinic	(907) 659-7230		

Alaska Clean Seas (OSRO)

Alaska Clean Seas	(907) 659-2405 (24 hour)
ACS Operations Manager	(907) 659-3202
ACS Western Ops Supervisor (Kuparuk)	(907) 659-7919
ACS Lead Spill Technician (Kuparuk)	(907) 659-7879
ACS Spill Technicians (Alpine)	(907) 670-4586

Mutual Aid

ACS Base	(907) 659-2405

Other Support

Wild Well Control, Inc. (Well Control)	1-281-784-4700
Lounsbury & Associates (surveys, maps)	(907) 659-7313
LCMF (Alpine on-site survey group)	(907) 670-4739
Alpine Weather	(907) 670-2210
Prudhoe Weather	(907) 659-5883

FIGURE 1-1: SPILL REPORT NOTIFICATION

Kuparuk Spill Report Notification

DATE:_____ **TIME:**_____ **RECEIVED BY** _____.

Important: Security personnel must ask the caller the following questions to determine whether an **emergency** exists. If an emergency, Security must initiate emergency call-out procedures.

Is anyone hurt? _____
Is there a fire or safety hazard? _____
Is this a line rupture, blowout, or corrosion leak? _____
Is the spill continuing to release? _____
Is spill about to travel off a gravel pad or road? _____
Did spill reach a river or waterway? _____

Contact Environmental Immediately if ANY of the following questions have a YES answer:

Is the spill >55 gal.? _____
Is the spill a chemical (except for produced water, glycol, drilling fluids, brine, seawater, or methanol diluted with >40% water)? _____
Is the spill to Tundra or to a Water Body? _____

659-7212 or 659-7242, pager 669

Record verbal spill information below:

Please note that all the information below is necessary for Agency reporting, please provide complete information.

Caller (Name/Phone): _____

Responsible Party (Company): _____

Responsible Supervisor (Name/Phone): _____

Date and Time Spill Occurred (or was first observed):_____

Location/Facility (include module #s.): _____

Material (if mixture, what are estimated %'s): _____

Estimated Volume of Release (total): _____ **If >55 gallons, contact SRT 659-7879/Pager 801**

Into secondary containment? No ☐ Yes ☐ Volume: _____

Inside building/module? No ☐ Yes ☐ Volume: _____

Did Spill Reach:

Water body: No ☐ Yes ☐ Volume: _____ **If "Yes", contact SRT 659-7879/Pager 801**

Tundra: No ☐ Yes ☐ Volume: _____ **If "Yes", contact SRT 659-7879/Pager 801**

Ice pad/road: No ☐ Yes ☐ Volume: _____

Gravel pad/road: No ☐ Yes ☐ Volume: _____

Is the spill along the Spine Road or 1C bypass? (Potentially in DOT ROW) No ☐ Yes ☐ **If "Yes", contact CPF3 Board 659-7444**

Environmental: Contact NSK Pipeline Coordinator Immediately 659-7574, Pager 467 if any emergency conditions above are "YES" or if it is a spill to water and the spill is in or potentially in the ROW. If it is in the ROW but not an emergency/immediately reportable event, fax report to the NSK Pipeline Coordinator at 659-1743. Check the ROW maps for additional locations (i.e. CPF1 and CPF2). **Ensure Responsible Party gets a GPS location for any ROW area spills.**

Spill Surface Area (estimate sq. ft.): _____

Cause: _____

Source (tank, well, pipeline, vehicle nos.?): _____

Is cleanup assistance required? No ☐ Yes ☐ **If "Yes", contact SRT 659-7879/Pager 801**

Charge Code _____

Cleanup Actions (equipment used? % recovered?) _____

Disposal/Reuse/Recycle Location_____

Complete this form & fax to Environmental at 659-7712, and to Spill Response Technicians at 659-7926

FIGURE 1-2:
EMERGENCY RESPONSE NOTIFICATION PLAN –
MINOR, LEVEL I, LEVEL II, OR LEVEL III

EMERGENCY OBSERVER: Person discovering emergency notifies Board Operator of location and nature of emergency.

BOARD OPERATOR / AREA SUPERVISOR: Confirms location and nature of emergency and notifies Security.

SECURITY: Security will determine the level of the emergency as shown below.

MINOR SPILL/INCIDENT

Notify affected area Supervisor

Notify Environmental
X-7242/7212, pager 189-669

Kuparuk Pipeline Spill
Notify Milne Point, and Alyeska
Pipeline Service Company (Alyeska)

LEVEL I INCIDENT

Notify affected area Supervisor

Notify Emergency Response Chief
X-7494/7843, pager 189-400

Notify Environmental
X-7242/7212, pager 189-669

Initiate Group SRT/IMT/Fire/HazMat/Rescue per
Emergency Response Chief
pager 189-400
Repeat page every 3 minutes.

Provide Kuparuk Operations Manager with Spill or
Incident Report

Kuparuk Pipeline Spill
Notify Milne Point and Alyeska

LEVEL II INCIDENT

Notify Emergency Response Chief pager
189-400

SRT/IMT/HMRT with instructions pager 189-602

ACS, Mutual Aid needed
9-659-2405

Kuparuk Pipeline Spill
Notify Milne Point and Alyeska

Otter Pilots to activate FLIR

Notify Safety Department pager 189-674

Notify Facility HSET Specialist (as required)
CPF 1 = 189-671
CPF 2/3 = 189-672

Notify Environmental 189-669

LEVEL III INCIDENT

Notify Emergency Response Chief pager
189-900

SRT/IMT/HMRT with instructions pager 189-602

ACS, Mutual Aid needed
9-659-2405

Kuparuk Pipeline Spill
Notify Milne Point and Alyeska

Otter Pilots to activate FLIR

Notify Safety Department pager 189-674

Notify Facility HSET Specialist (as required)
CPF-1 = 189-671
CPF-2/3 = 189-672

Notify Environmental 189-669

Identify Off-Slope resources needs and communicate to
the appropriate response group.

MINOR SPILL: No SRT immediate response required. Send spill report to Environmental, NSK-61

LEVEL I: Can manage with the resources on site.

LEVEL II: Will need assistance from North Slope Mutual Aid responders.

LEVEL III: Will need assistance from North Slope Mutual Aid responders plus off-Slope resources.

1.2.2 External Notification Procedures [18 AAC 75.425(d)(1)(B)(ii)]

State of Alaska regulations at Title 18 of the Alaska Administrative Code (AAC), Chapter 75 (18 AAC 75.300) require prompt notification to the Alaska Department of Environmental Conservation of hazardous substance spills other than oil, any oil spill to water, or an oil spill solely to land outside of secondary containment if greater than 55 gallons. Notification within 48 hours is required for oil spills to land in excess of 10 gallons, but 55 gallons or less, or greater than 55 gallons if spilled into secondary containment.

The CPAI Field Environmental Coordinator is responsible for notifying the appropriate regulatory agencies. Agency contact information is included in Table 1-4. Depending on the type of spill, agency verbal notifications and written reports may include:

- National Response Center (NRC),
- U.S. Environmental Protection Agency (EPA),
- U.S. Coast Guard (USCG),
- U.S. Department of Interior, Bureau of Land Management (BLM),
- U.S. Department of Transportation (DOT),
- U.S. Fish and Wildlife Service (USFWS),
- Alaska Department of Environmental Conservation (ADEC),
- Alaska Oil and Gas Conservation Commission (AOGCC),
- Alaska Department of Natural Resources (ADNR),
- Alaska Department of Fish and Game (ADF&G),
- North Slope Borough (NSB), and
- U.S. Department of the Interior, Bureau of Safety and Environmental Enforcement (BSEE).

TABLE 1-4:
AGENCY NOTIFICATION INFORMATION

AGENCY	PHONE	FAX
NRC	(800) 424-8802 (202) 267-2675	
EPA (NRC will call)	(907) 271-5083	(907) 272-0690
EPA (Seattle) National Pollutant Discharge Elimination System (NPDES) Compliance Unit	(206) 553-1846	
EPA (Seattle) 24 hours	(206) 553-1263	(206) 553-0175
ADEC – business hours	(907) 451-2121	(907) 451-2362
ADEC – after hours and on weekends call Alaska State Troopers	(800) 478-9300	
ADEC – sewage spills only (Division of Water Non-Compliance Reporting Hotline – Recording)	(907) 269-4114 Toll Free (Nationwide) 24 Hr Message Machine (877) 569-4114 dec-wqreporting@alaska.gov	(907) 269-4604
ADNR – recording	(907) 451-2678	(907) 451-2751
Alaska State Fire Marshal's Office	(907) 269-5491	(907) 378-4375
NSB Local Emergency and Planning Committee (LEPC) and NSB Risk Management	(907) 852-0284	(907) 852-0356
NSB Waska Williams (Office)	(907) 852-0440	(907) 852-5991
NSB Permitting and Zoning Division	(907) 852-0320	(907) 852-5991
NSB Police	(907) 852-6111 (24 hours on call)	(907) 852-0248
City of Nuiqsuit	(907) 480-6727	(907) 480-6928
Kuukpik Corporation	(907) 480-6220 Toll Free (866) 480-6220	(907) 480-6126 (primary) (907) 480-6210 (secondary)
USCG	(907) 271-6700	(907) 271-6765 (primary 24-Hr fax) (907) 271-6751 (secondary)
BSEE	(907) 334-5309	
ADF&G – Fairbanks (Wildlife Information Center)	(907) 459-7206 or (907) 459-7306	(907) 456-7303 (Habitat Division)
AOGCC – Anchorage	(907) 279-1433	(907) 276-7542
AOGCC – Field (Slope Pager)	(907) 659-2714 (Pager 659-3607)	(907) 659-2717
BLM Anchorage – National Petroleum Reserve – Alaska (NPRA)	(907) 267-1246	(907) 267-1304
BLM Fairbanks – NPRA Seismic spills to Fairbanks only; other BLM spills to both Fairbanks and Anchorage	(907) 474-2309	(907) 474-2386
Kuparuk Pipeline		
DOT contact NRC	(800) 424-8802 (24 hours)	
DOT – Local DOT office	(907) 271-6517	
DOT –Pipeline and Hazardous Materials Safety Administration Office of Pipeline Safety	(202) 366-4595	
Contact CPAI Pipelines Engineering & Operations Manager if >5 bbls Hazardous liquid and file accident report (FM7000-1) no later than 30 days of discovery.		
State Pipeline Coordinator's Office (SPCO) – General Office	(907) 269-6403	(907) 269-6880
SPCO – Director, Ray Jacubzak Deputy Pipeline Coordinator Natural Resource Manager III	(907) 269-6899 (907) 269-6419 (907) 269-6419	(907) 269-6880

Additional Notifications

Federal law requires that at least one of its representative agencies be notified of qualifying spills of oil or hazardous substances. Federal law also requires the NRC be notified of all hazardous substance spills that exceed the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) reportable quantity limit. This notification should be made within two hours of the incident.

DOT requires notification of any spills from the Kuparuk Pipeline that involves one or more of the following conditions:

- Explosions or fires;
- Death or personal injury requiring hospitalization;
- Estimated damage to property of $50,000 or more; or
- Pollution of any body of water.

DOT requires information on weather conditions for any reported spill.

The NSB and the Alaska Pipeline Commission have a stipulation within the "Certificate of Public Convenience and Necessity" that requires CPAI to notify them of any spills from the Kuparuk Pipeline or any joint or connection to the line.

1.2.3 Written Reporting Requirements

Depending on the type and amount of material spilled, individual government agencies have written reporting requirements. The Field Environmental Coordinator is responsible for spill reporting to various governmental agencies. These reporting requirements are detailed in Table 1-5.

State of Alaska regulations (18 AAC 75.300) require prompt notification to ADEC of hazardous substance spills other than oil, any oil spill to water, or an oil spill solely to land outside of secondary containment, if greater than 55 gallons. Notification within 48 hours is required for oil spills to land in quantities greater than 10 gallons, but 55 gallons or less; or greater than 55 gallons, if the release is from the original storage tank, pipeline, or other immediate container, and the release is spilled into secondary containment. After notification of the discharge has been made to ADEC, the department will, at its discretion, require interim reports to assess human or environmental threat. A written final report must be submitted within 15 days of the end of cleanup operations, or if no cleanup occurs, within 15 days of the discharge. Interim and final written reporting requirements are specified in 18 AAC 75.300 and must contain the following information:

- Date and time of discharge;
- Location of discharge;
- Name of facility or vessel;
- Name, mailing address, and telephone number of person or persons causing or responsible for the discharge and the owner and the operator of the facility or vessel;
- Type and amount of each hazardous substance discharged;
- Cause of the discharge;
- Description of any environmental damage caused by the discharge or containment, to the extent the damage can be identified;

- Description of cleanup actions taken;
- Estimated amount of hazardous substance cleaned up and hazardous waste generated;
- Date, location, and method of ultimate disposal of the hazardous substance cleaned up;
- Description of actions being taken to prevent recurrence of the discharge, and
- Other information the department requires to fully assess the cause and impact of the discharge.

A person in charge of a facility or operation shall maintain, and provide to ADEC on a monthly basis, a written record of any discharge, including a cumulative discharge, of oil solely to land from 1 to 10 gallons.

TABLE 1-5:
AGENCY REPORTING REQUIREMENTS FOR OIL SPILLS AND HAZARDOUS MATERIALS

AGENCY	LOCATION / RECEIVING ENVIRONMENT	SPILL SIZE	VERBAL REPORT	PHONE NUMBER	WRITTEN REPORT
Alaska Department of Environmental Conservation (ADEC) Alaska Department of Natural Resources (ADNR) (same requirements as ADEC) *Alaska Department of Fish & Game (ADF&G) (any release to fish-bearing waters)* *Kuukpik Corporation (within Kuukpik withdrawal area or if IMT is activated)*	Off pad to water or tundra	Any	Immediately (within 30 minutes)	ADEC (business hours) (907) 451-2121 (907) 451-2362 (fax) or Alaska State Troopers (after hours and weekends) (800) 478-9300 ADNR (907) 451-2678 (907) 451-2751 (fax) ADF&G – Fairbanks (907) 459-7206 (907) 456-3091 Kuukp k (907) 480-6220 (907) 480-6126 (fax)	Submit within 15 days after containment and cleanup are completed or, if no cleanup occurs, within 15 days after the discharge or release.
	On gravel pad, gravel road, ice pad, ice road, or snow-covered tundra	1 to 10 gallons (< 1 gallon no report)	Monthly written report		
		> 10 to 55 gallons	Within 48 hours		
		> 55 gallons	Immediately		
	Into impermeable secondary containment area or structure	> 55 gallons	Within 48 hours		
Alaska Oil and Gas Conservation Commission (AOGCC)	Well release (crude or gas)	Any	Immediately	Anchorage (907) 279-1433 (907) 276-7542 (fax) North Slope (Field) (907) 659-2714 (907) 659-3607 (pager) (907) 659-2717 (fax)	Submit within 5 days of loss; final report required within 30 days.
National Response Center (NRC) U.S. Environmental Protection Agency (EPA) and U.S. Coast Guard (USCG)	Into or upon navigable waters of the U.S. or to land that may threaten navigable waters of the U.S.	Any	Immediately	(800) 424-8802 (24 hour)	Form completed during phone notification. For SPCC facilities, if spill is ≥ 1,000 gallons or if it is a second spill > 42 gallons in 12 months to water or tundra, submit written report to EPA.
North Slope Borough (NSB)	Off pad to water or tundra	Any	Immediately	First Responders (907) 717-5668 (907) 480-6818 Permitting and Zoning (907) 852-0440 (907) 852-5991 (fax) LEPC - Risk Management (907) 852-0248 (907) 852-0356 (fax)	Submit within 7 days.
	On gravel pad, gravel road, ice pad, ice road, or snow-covered tundra	> 55 gallons	Immediately		
	Into impermeable secondary containment area or structure	> 55 gallons	Within 48 hours		
State Pipeline Coordinator's Office (SPCO) U.S. Department of Transportation (DOT)	From pipeline administered by the SPCO or to pipeline ROW	Any	Immediately	SPCO (907) 257-1300 (907) 272-0690 (fax) NRC (800) 424-8802 (24 hour) DOT – Anchorage (907) 271-6519	Submit DOT Form 7000-I within 30 days (see form for details).
	From DOT-regulated pipeline	≥ 5 gallons			

1.3 SAFETY [18 AAC 75.425(e)(1)(C)]

The principal sources of information concerning safety procedures and practices to be followed in the event of a spill are:

- The ACS *Technical Manual*, which includes site entry procedures, site safety plan development, and personnel protection procedures.
- The *Alaska Safety Handbook*.
- CPAI's emergency action plans, which reference standard operating procedures (SOPs), operating manuals, and emergency procedures.
- Facility evacuation plans and diagrams contained in the emergency action plans.

The Incident Commander and the Safety Unit Leader will document initial assessment and response plan recommendations using the ICS. The ICS uses standard forms that contain information to verify a safety plan is formulated and is easily communicated to management and response team members.

1.4 COMMUNICATIONS [18 AAC 75.425(e)(1)(D)]

The Kuparuk spill communication system supports the organizational structure of spill response efforts and is scalable in both size and scope to serve both small- and large-scale response events. An event that is limited to a local response by the SRT is comfortably served by the local SRT communications system. An event that invokes a response by ACS or involves a significant Mutual Aid effort with other North Slope operators is able to use ACS communications equipment and upgrade smoothly from the local communication system to the ACS wide-area system. Radio equipment is described below.

The CPAI communication resources available for spill response may be loosely classified into the following three categories:

- **CPAI SRT Telecom Resource:** Communication resources that are designed to support spill response and have been developed for the SRT and the CPAI Incident Command Post (ICP).
- **ACS Telecom Resource:** Communication resources that are part of the ACS Telecommunications Plan. These resources are available for CPAI and other North Slope operators including ACS.
- **Kuparuk Telecom Resource:** Communication resources that were not designed exclusively for spill response but may directly or indirectly play an important supportive role towards a successful response effort.

The Communications Unit Leader will provide the communications system necessary to support the response actions of the SRT. Whenever possible, the communications system established for spill response will use the existing communications network, headquartered in the ICP Communications Module of the Kuparuk Emergency Operations Center (EMOC). The communications system at Kuparuk is tied into the communications system at Alpine and Prudhoe Bay by microwave channels.

1.4.1 Spill Response Incident Command Post Communication

The Kuparuk EMOC conference room is the designated ICP for management personnel during a major spill. The main phone number for the ICP is extension 7792. Additional phones and a facsimile machine are provided for outgoing incident management and incident support calls, and as rollovers when the main line is busy.

1.4.2 UHF and VHF Networks

CPAI maintains ultra high frequency (UHF) and very high frequency (VHF) networks for daily operations and oil spill response. A list of on-site radio equipment is listed in Table 1-6.

The CPAI Kuparuk Security/Message Center, ICP Dispatch/Message Center, and SRT offices have desktop remote control of a UHF base station to provide communications on the UHF oil spill channel. This channel is used and shared by other North Slope area spill responders in addition to, and as a backup for, the VHF oil spill channel.

CPAI vehicles are normally equipped with a CPAI-network UHF mobile radio. This includes the vehicles or heavy equipment that may support a typical spill response. The North Slope Emergency Response Chief's CPAI vehicle is equipped with a mobile-trunked radio unit.

All spill response vehicles, and the Mobile Command Center, are equipped with frequency-agile, high-band VHF and UHF radios. This capability coordinates SRT with the North Slope Operating Area frequency plan, and includes access to CPAI mobile communication channels.

Kuparuk has mobile units and portable two-way radios that are compatible with the VHF Oil Spill Frequency. Key spill response personnel are issued this equipment by the Spill Response Center for overall coordination of localized and Mutual Aid cleanup activities.

1.4.3 Other Networks

Mobile telephone services form an important part of the spill response communications. The CPAI Mobile Command Center, North Slope Emergency Response Chief's truck, SRT Tech trucks, and Spill Van all have a mobile telephone available. The SRT Command trailer also has a permanently installed bush phone to provide a telephone line for a mobile fax machine.

A portable 2-GHz microwave shelter, housing a 24-channel microwave system, has been mounted on a small vehicle trailer that can be used to provide communications to the mobile Staging Area Manager's Office. This includes one network link with access to the CPAI computer network, one telephone line to connect a facsimile machine, and four standard telephone lines.

Key operating personnel also carry pagers that can be activated by telephone for an individual or for a group, such as the SRT and the Kuparuk Fire Department. Personnel may also be contacted by phone in their quarters at the Kuparuk Operations Center. The Kuparuk Operations Center and other major sites have public address systems and private electronic systems for internal communications.

The Kuparuk EMOC Communications Module also has marine and ground-to-air frequencies.

(b) (7)(F), (b) (3)

1.4.4 ACS Communications

1.4.5 Integrated Communications

The initial communications employed during emergencies and responses to releases are integrated into the Kuparuk Operations network to facilitate communications among the various operations during an incident. When an emergency response is initiated, Security personnel will contact the North Slope Emergency Response Chief by a pager or land line.

While the initial response is in effect, the North Slope Emergency Response Chief is operating on two UHF channels:

- The operations frequency for the area in which the incident is occurring; and
- The fire department's tactical network.

This allows for close communications among the fire department, North Slope Emergency Response Chief, and Operations to maximize protection of personnel at the incident scene. If the situation warrants, the SRTs are contacted and either activated or placed on standby through land line, pagers, or UHF radios.

The UHF network is available to the SRT, spill contractor, and the ICS command post. As the response progresses, the communication plan will be updated to reflect the appropriate needs and methods of communications. As the scale of activities increases, the portable VHF radios will be issued and the response will be directed in the communication plan to operate on the dedicated [redacted] (b)(3). The VHF and UHF networks are available at the command post. VHF is available at the field level when the communication units are issued to the SRT, the spill response contractor, and field-deployed agency personnel.

1.5 DEPLOYMENT STRATEGIES [18 AAC 75.425(e)(1)(E)]

Spill response equipment and supplies are available for immediate deployment through the North Slope Emergency Response Chief, or they are pre-deployed at the Central Production Facilities (CPFs), along the Kuparuk River, and on the coastline. Special 40-foot-long "Spill Vans" at the Kuparuk EMOC at CPF-1 pad are equipped for moderate to large spills and can be rapidly deployed by towing to the spill site on the Kuparuk road network. Both CPF-2 and CPF-3 have a local response spill van that can be rapidly deployed with a pickup truck or front-end loader. These vans are designated as "CPF Spill Vans" and are equipped with response equipment for any SRT member responding to a minor to moderate spill at a particular facility. Connex containers located along the Kuparuk River are designated as "River Connexes" and hold containment boom and associated materials. A spill connex container will be staged at drill site (DS) DS-3G to provide rapid response to the DS-3S area. The Kuparuk Sales Oil Pipeline crosses the Putuligayuk River northwest of Pump Station 1. There is a seasonal containment site located

downriver from the pipeline crossing north of the Spine Road (Reference: Sheet 77, ACS *Technical Manual,* Volume 2, Map Atlas).

Additional locations of pre-staged equipment are included in the ACS *Technical Manual,* Volume 2, Map Atlas Sheets 27-29, 35, 39-42, 45-46, 51, 69-70, and 76-77.

1.5.1 Transport Procedures [18 AAC 75.425(e)(1)(E)(i)]

CPAI daily operations provide an infrastructure for a spill response. The extensive transportation infrastructure for personnel and equipment can support a small response and can be enhanced for a major spill. See ACS *Technical Manual* Tactic L-1.

Transportation options, depending on the location, season, availability, and weather, include vessels, road vehicles, tundra travel vehicles, helicopters, fixed-wing aircraft, and air-cushion vehicles. Ice roads may be constructed to provide remote site access.

The estimated response time from discovery of a spill to the deployment of equipment varies depending on the location, time of year, pre-planning, logistical support, and available information. These variables are discussed for each site-specific scenario provided in Section 1.6.3. For planning purposes, 5 knots is used for vessels, 100 miles per hour (mph) for helicopters, 150 mph for light fixed-wing aircraft, 300 mph for heavy fixed-wing aircraft, 5 mph for tundra travel vehicles, and 35 mph for road vehicles.

Listed below are the estimated response times for Kuparuk. These estimates do not include the time involved in a health and safety characterization or release of the site.

- Immediate response to a spill in the Kuparuk field will occur with the pre-staged response equipment.
- Flight time with light fixed-wing aircraft from Deadhorse is 30 minutes in good weather. The mobilization time is 1 hour from the notice to fly.
- Estimated road vehicle response time from Deadhorse to Kuparuk is 1 hour.
- The estimated response time to a spill along the Kuparuk pipeline route by the Kuparuk initial SRT is within 1 hour.
- The travel and deployment time from West Dock to Oliktok Dock for marine equipment is 5 to 6 hours after the vessel is underway. The preparation time is approximately 4 hours if the vessel is on standby; otherwise, the mobilization time can be measured in days.

TABLE 1-7:
SEASONAL TRANSPORTATION OPTIONS

MODES OF TRANSPORTATION	SUMMER	WINTER	BREAK-UP/FREEZE-UP
Vessel	X		
Helicopter	X	X	X
Fixed-wing aircraft	X	X	X
Road vehicle	X	X	X
Tundra travel vehicle	X	X	X

Estimated times for transportation of containment, exclusion, and recovery equipment are summarized in the ACS *Technical Manual* Tactics L-3 and L-4.

1.5.2 Notification and Mobilization of Response Action Contractor [18 AAC 75.425(e)(1)(E)(ii)]

Sections 1.1 and 1.2 of this ODPCP describe immediate response and notification actions, which include notification of ACS. While ACS is mobilizing personnel and equipment to the spill site, CPAI personnel determine safety procedures, notify government agencies and CPAI personnel, and proceed with source control measures. In addition, and if safe to do so, CPAI response personnel will deploy on-site spill containment equipment.

The on-site personnel are the initial responders to spills at or near their production facilities. The SRT will respond promptly upon notification. Equipment will be deployed in the manner appropriate to the type of spill, based on the containment tactics established in the ACS *Technical Manual*.

Pre-staged and pre-deployed oil spill response equipment is discussed in Section 3.6.

1.6 RESPONSE STRATEGIES [18 AAC 75.425(e)(1)(F)]

The following subsections provide information on the strategies for responding to incidents at Kuparuk. This information supports the discussions in Section 1.6.3. Where warranted, a narrative discussion has been provided; otherwise, the reader is directed to the relevant portion of the scenarios.

1.6.1 Qualifier Statement

The scenarios and response strategies described in this plan were developed according to 18 AAC 75.425(e)(1)(F) and (I). They describe general procedures, equipment, personnel, tactics, strategies, and operational capabilities that can be used to respond to an oil spill. These scenarios are presented for illustration purposes only and are not performance standards or guarantees of performance. The scenarios assume hypothetical conditions of the spills and responses to demonstrate CPAI's ability to respond to a discharge of each applicable response planning standard (RPS) volume within the required time frames using the resources described in this ODPCP and as required by 18 AAC 75.425(e)(1)(F) and (I). The RPS volume calculations are presented in Part 5.

The scenarios identify the location, time of year, time of day, source and cause of spill, quantity and type of oil spilled, relevant environmental conditions (including weather, sea state, and visibility), spill trajectory, expected timeline for response actions, and a description of response actions to be taken. The response scenarios and strategies are usable as a general guide for a discharge of any size and describe the discharge containment, control, and cleanup actions to be taken, which demonstrate the strategies and procedures adopted to conduct and maintain an effective response.

Well blowout scenarios include a summary of planned methods, equipment, logistics, and time frames proposed to be employed to control a well blowout within 15 days. CPAI also certifies that they currently have and continually maintain a separate blowout contingency that is available to ADEC upon request.

The response strategies illustrate specific response measures that can reduce the risk, magnitude, or environmental impact of an oil spill, considering the variation of receiving environments and seasonal conditions.

The response scenarios include the following:

i. Procedures to stop discharge;
ii. Fire prevention and control;
iii. Not used (associated regulation repealed 5/26/2004);
iv. Discharge tracking;
v. Protection of sensitive areas;
vi. Containment and control strategies;
vii. Recovery strategies;
viii. Damaged tank transfer – Lightering procedures;
ix. Transfer and storage strategies;
x. Temporary storage and ultimate disposal;
xi. Wildlife protection; and
xii. Shoreline cleanup.

Some details in the scenarios are for illustration purposes, and although some equipment is named, it may be replaced by functionally similar equipment (e.g., a dump truck may be used in winter when there is road access, or an end dump trailer pulled by a semi chassis may be the functional equivalent to perform a similar task in summer). These details do not limit the discretion of the persons in charge of the spill response to select any sequence or take whatever time they deem necessary to respond to a spill without jeopardizing personnel safety.

All pre-staged spill response equipment at Kuparuk can be located in the ACS *Technical Manual,* Volume 2, Map Atlas. The specific map sheets that illustrate pre-staged equipment are:

- Map Sheet 28, MW-1 at DS-2N;
- Map Sheet 28B, MW-2 at DS-2P;
- Map Sheet 35, KUP-11 and 12 at DS-3R and Oliktok;
- Map Sheet 41, KUP-10 at CPF-3;
- Map Sheet 45, Seasonal boom pre-deployment site at Kalubik Creek;
- Map Sheet 45A, Seasonal boom pre-deployment site;
- Map Sheet 54, KUP-9 at CPF-2;
- Map Sheet 57, KUP-8;
- Map Sheet 61, KUP-6 and 7, Gwyder Bay South; and
- Map Sheet 63, KUP-2,3,4 and 5, Kuparuk River.

In situ burning could be used in a spill response to reduce the quantity of oil, regardless of whether a scenario hypothesizes in situ burning to help meet the RPS. Sections 3.4 and 3.7 describe the in situ burning capabilities of CPAI and ACS during varying seasonal conditions.

Actual responses in an oil spill emergency depend on personnel safety considerations, weather, other environmental conditions, agency permits and priorities, and other factors. In any incident, considerations to ensure the safety of personnel will be given highest priority. If severe weather or other conditions limit the safety of personnel, CPAI may take precautions up to and including suspending response efforts until it is deemed safe to proceed. Likewise, if operating limitations are reached because of weather conditions, CPAI will reassess the response effort and take necessary precautions to protect personnel and equipment. The scenarios assume the agency on-scene coordinators and other agency officials will immediately grant any required permits.

1.6.2 Temporary Storage and Disposal [18 AAC 75.425(e)(1)(F)(x)]

Temporary storage of oil, oily waste, and debris recovered during a spill cleanup may be provided by tanks, pits, or basins located at facilities near the site. The spill location or logistical issues may require storage of oil, oily waste, and debris in smaller, more portable containers that can be brought to the scene via truck, boat, or aircraft.

Other temporary storage options during a spill response include lined natural depressions (approval required), construction of lined earthen dikes, and portable storage (e.g., bladder tanks, inflatable tanks, open-top drums, vacuum trucks, dump trucks, etc.).

Kuparuk River Unit (KRU) DS-1H is a permitted solid waste storage facility and may be used for contaminated gravel and/or snow storage.

The method of disposal for oil and contaminated materials from spill recovery operations (or for oily waste from normal operations) must be approved by the appropriate state and federal agencies. At the time of the spill, the Operations Chief, in consultation with the Environmental Unit Leader, determines the reuse, recycling, or disposal method best suited to the state of the oil, the degree of contamination of recovered debris, and the logistics involved in these operations. Application for agency approvals are completed before the determined method of disposal is implemented. An initial determination must be made regarding the classification of the waste as exempt, hazardous, or non-hazardous. This classification can be made on a case-by-case basis. The Environmental Unit Leader provides assistance in determining the classification if the status of the waste material is in question. In general, the following guidelines apply:

- Spills from DOT pipelines are non-exempt and may need to be tested to determine if the material is hazardous. Previous sample data of adequate process knowledge may alleviate the need for testing.
- Spills from production lines are exempt and therefore non-hazardous.
- Spilled material that comes out of a well, either during drilling or workover operations, is exempt and therefore non-hazardous. Spilled material that did not come out of a well may not be exempt and might have to be tested to determine if the material to be disposed of is hazardous.
- Spills that occur from filling a tank (e.g., vehicle, storage, etc.) are non-exempt. Though they may occur on a well pad, product knowledge or testing may be needed to determine if the material to be disposed of is hazardous.

Should materials need to be transported off the North Slope, truck, barge, and/or air transportation will be arranged.

1.6.3 Response Scenarios [18 AAC 75.425(e)(1)(F) and 18 AAC 75.425(e)(1)(I)]

This section contains spill response strategies that address the following spill scenarios:

- Drill Site 2A, Well 2A-15 Production Well Blowout – Summer
- Drill Site 2A, Well 2A-15 Production Well Blowout – Winter
- Kuparuk Pipeline Spill – Summer
- CPF-2 Divert Tank Rupture – Summer
- Response Strategy – DS-3R Production Well Blowout During Summer

SCENARIO 1

KUPARUK DS 2A PAD

DS 2A-15 PRODUCTION WELL BLOWOUT DURING SUMMER

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TABLE 1-8:
DS 2A-15 PRODUCTION WELL BLOWOUT DURING SUMMER SCENARIO CONDITIONS

PARAMETER	PARAMETER CONDITIONS
Spill Location	Production well DS 2A-15 on DS 2A Pad
Date	August 1
Duration	15 days
Type of Spill	Uncontrolled well blowout through open orifice (without assisted lift)
Quantity of Oil Spilled	
Oil Type	Alaska North Slope Crude
Emulsification Factor	1.67 (Applicable to oil that reaches open water, for storage purposes.)
Wind Direction	Wind data are derived from the Kuparuk meteorological station (see Figure 1-3). The data used were collected during summer months (May through October) from May 2005 through October 2011. The predominant wind directions are ENE and E. The mean wind speed is 10 knots. The relative percentages of these predominant winds are the following: • Day 1 through 7: wind from ENE (N67.5°E) • Day 8 through 15: wind from E
Current	Not applicable
Air Temperature	51 degrees Fahrenheit (F)
Surface	Well location is a gravel pad; well is 450 feet from the western pad edge. Tundra and tundra lakes comprise the landscape south and west of the pad. Branches of Kalub k Creek are located west and east of the pad.
Trajectory	The simulated blowout is discharging at a rate of 540 bpd with a gas-to-oil ratio (GOR) of 6,382 standard cubic feet per barrel (scf/bbl) through a 6.3-inch-diameter pipe. The SL Ross plume dispersion model published in ACS *Technical Manual* Tactic T-6 projects that the oil takes the form of an aerial plume extending from the well in the direction of the predominant wind directions. The model projects a gas flow of approximately 3.4 million standard cubic feet (scf) of gas per day. The model predicts the following plume dimensions: • Approximately 80 percent of the discharged oil falls within 700 feet downwind of the well. At that distance, each fallout plume is about 137 feet wide. • Ninety percent of the discharged oil falls within 4,873 feet downwind of the well. At that distance, each fallout plume is about 786 feet wide. • According to the SL Ross model, 10 percent of discharged oil is in the form of droplets so small (50 micrometers or less) that they do not fall to the ground. As a conservative measure for response planning purposes, the volume of oil that is predicted to stay aloft is proportionally distr buted between the two modeled fallout zones. Consequently, the scenario addresses the full RPS volume of 8,100 barrels. The distribution of oil within the fallout plumes is detailed in Table 1-9. Approximately 6,075 barrels of the discharged oil falls on the pad. Not all of the oil falling on the pad is retained by the gravel. If not recovered, discharged oil accumulates in low-lying areas and eventually flows off the pad. Approximately 2,025 barrels of oil falls beyond the pad, impacting tundra, ponds, and creek beds.

TABLE 1-9:
RESPONSE STRATEGY
DS 2A-15 PRODUCTION WELL BLOWOUT DURING SUMMER

ADEC REQUIREMENT	RESPONSE STRATEGY	REFERENCES TO THE ACS TECHNICAL MANUAL AND THIS PLAN
(i) Stopping Discharge at Source	Efforts are made to bring the well under control. Emergency shutdown procedures are initiated. Once it has been determined that control of the well cannot be immediately regained, or the safety of personnel is at risk, personnel are evacuated to pre-designated safe areas with adequate shelter, minimal survival equipment, and communication equipment. At all times, the safety of personnel is the first concern. No unauthorized personnel are allowed near the spill area. The well continues to blow out. The Wells Supervisor notifies the Wells Superintendent. All appropriate notifications are made. The IMT is activated. The On-Site Company Representative calls Wild Well Control at 1-281-784-4700. Wild Well Control is dispatched from Houston within 12 hours. Wild Well Control initiates attempts to stop the blowout using the appropriate well control methods. Surface methods control the blowout on Day 15.	Section 1.2 Table 1-2, Section 1
(ii) Preventing or Controlling Fire Hazards	Throughout the first few hours of the spill, the Site Safety Officer verifies that all sources of ignition are shut down or removed from the area. The Site Safety Officer provides access zone information and determines personal protective equipment (PPE) requirements. Access to the spill site is carefully controlled and the scene is secured by Security. Monitoring protocol is established by the Site Safety Officer for all work areas to ensure personnel protection. This monitoring protocol will establish personnel and equipment safety zones according to applicable Occupational Safety & Health Administration (OSHA) and fire hazard standards. Containment and recovery operations are allowed without respiratory protection in areas where safety criteria are met. Recovery operations are not allowed downwind of the blowout well in areas where workers may become exposed to flash fire hazard or oil particulate matter at concentrations in excess of permissible exposure limits.	S-1 Through S-6
(iv) Surveillance and Tracking of Oil	Once safety zones and protocols are established, oil movement is tracked by land mapping and aerial surveillance. A blowout plume model is run using conditions observed at site.	T-2 T-6
(v) Exclusion Procedures	No priority protection sites exist within the projected discharge plume. Portions of Kalubik Creek are listed as anadromous by ADF&G. The projected discharge plume does not fall to Kalubik Creek, and is approximately 1.5 miles south of the designated portion. General sensitivities of the area are detailed in Sheets 49 and 53 of Volume 2 of the ACS *Technical Manual*. Kalubik Creek contains seasonally pre-deployed boom approximately 5 miles north of DS 2A.	ACS Map Atlas Sheets 49 and 53
(vi) Spill Containment and Control Actions	**Day 1** CPAI, in conjunction with ACS, begins activating the appropriate pre-approved permits needed for spill response operations. Containment and recovery operations begin after safety protocols are established. Work conducted near the blowout is carefully monitored for safety; no ignition sources are allowed in hot zones and proper PPE is required (see part ii above). Upon initial reports of the blowout, CPAI and ACS begin transportation of containment and recovery equipment to a staging area at Kuparuk West Sak 14. **Task Force 1 (TF-1) – Containment** During Day 1, TF-1 teams build trenches and berms at strategic locations on and off the pad to contain oil and control its movement into areas where recovery can occur. Initial construction starts upwind and crosswind of the aerial plume. Trenches and berms are also used to separate pooled oil from vehicle access routes. Where appropriate, shore seal boom is used for containment in areas off-pad. TF-1 consists of 2 teams equipped with a front-end loader, backhoe, and skid steer.	A-3 L-3 C-4

TABLE 1-9 (CONTINUED): RESPONSE STRATEGY DS 2A-15 PRODUCTION WELL BLOWOUT DURING SUMMER

ADEC REQUIREMENT	RESPONSE STRATEGY	REFERENCES TO THE ACS TECHNICAL MANUAL AND THIS PLAN
(vi) Spill Containment and Control Actions (continued)	**Days 2 to 15** Throughout Days 2 to 15, TF-1 continues to build, shore, and maintain the berms and trenches as necessary.	
(vii) Spill Recovery Procedures	**Days 1 to 7** On Day 1, the equipment for the recovery, transfer, and interim storage of recovered oil are trucked to the staging area. Recovery begins once staging areas and safety protocols are established. Information on heavy equipment for the response is presented in Table 1-14. Lists of personnel for recovery operations are detailed in Table 1-15. Limited liquid recovery occurs between Days 1 and 8. When the wind shifts, recovery equipment has access to the WSW plume. On Day 15, surface control is achieved allowing full access to the oiled areas. **Task Force 2 (TF-2) – Pad-Based Liquid Recovery Operations** Using two on-site vacuum trucks, pumps, and hoses, TF-2 begins recovery of oil from the drainage basins and the bermed and trenched areas containing oil. The former reserve pit provides a natural containment area that is used for recovery. Vacuum trucks are capable of recovering liquid oil up to 200 feet from the truck. Recovery continues as the blowout continues and as long as conditions allow for safe operations. **Task Force 3 (TF-3) – Off-Pad Liquid Recovery** By Day 2, TF-3 teams deploy three drum skimmers, two disc skimmers, and six rope mops to recover oil in off-pad ponds and tundra. They also take advantage of natural depressions, where oil collects in greater quantities. If possible, they enhance recovery using sheet metal containment, shore seal boom, and or deflection boom. Recovered oil is placed in Fastanks or similar portable storage with secondary containment, which remain at the TF-3 recovery sites. The recovered oil is transferred from the TF-3 site to vacuum trucks on the pad by a Rolligon with a tank. The derated recovery capacity of the drum/brush skimmer and the disc skimmer is 20 barrels per hour (bph) and 10 bph, respectively. The derated recovery rates of the rope mop skimmers are 3 bph. **Task Force 4 (TF-4) – Liquid Transport** TF-4 consists of a Rolligon with 10,000-gallon (238-barrel) trailer tank, and a vacuum truck. The Rolligon is capable of making five trips a day transferring 1,190 bpd to the pad, where it offloads to a vacuum truck. The vacuum truck transfers the fluid directly to CPF-1. The transfer rate from TF-3 recovery sites to the CPF-1 disposal site exceeds the projected fallout rate. See Table 1-10. **End of Day 7** As the wind shift changes the orientation of the plume fallout, containment and recovery crews adjust positions to recover oil that has collected in areas previously inaccessible. **Day 15** Once well control is achieved, recovery teams have full access to oiled tundra, water, and gravel. Task forces maximize the numbers of personnel and equipment. **Task Force 5 (TF-5) – Tundra Flushing** Two TF-5 teams begin the process of flushing oil from the tundra surface. TF-5 teams consist of a water truck operator and two general technicians. The tundra is flushed with water and oil is recovered by hand using sorbent materials. Residual oil will be recovered using two Rolligons with 10,000-gallon tanks and Manta Ray skimmers. Plywood walkways are used to minimize traffic damage to the tundra.	L-5, L-9 A-3 Section 1.6.2 R-6, R-7 R-8 R-23, R-6 R-4

TABLE 1-9 (CONTINUED): RESPONSE STRATEGY DS 2A-15 PRODUCTION WELL BLOWOUT DURING SUMMER

ADEC REQUIREMENT	RESPONSE STRATEGY	REFERENCES TO THE ACS TECHNICAL MANUAL AND THIS PLAN
(vii) Spill Recovery Procedures (continued)	**Task Force 6 (TF-6) – Pad Cleanup** Once liquid recovery task forces have ceased operations, cleanup and recovery operations of pad equipment and infrastructure are conducted on a non-emergency basis. A Pad Task Force (TF-6) pressure washes oil from the structures on the pad. The TF-6 team uses a water truck, Spillbuster van, and/or pressure washers. Once the structures have been cleaned, oily gravel is recovered and stored for proper disposal. **Task Force 7 (TF-7) – Oiled Gravel Recovery** After pad equipment is cleaned, front-end loaders are used to excavate oiled gravel and transfer it to dump trucks. The dump trucks transfer the oiled gravel to temporary lined containment cells near the DS4 Grind & Inject facility.	R-21 R-26
(viii) Lightering Procedures	Not applicable.	Not applicable.
(ix) Transfer and Storage of Recovered Oil/Water; Volume Estimating Procedure	Portable tanks containing fluids recovered by TF-2 and TF-3 provide sufficient storage for all oil recovered from water bodies off-pad. TF-2 vacuum trucks transport up to 3,600 bpd of recovered liquids directly to CPF-1. TF-4 and TF-5 Rolligons with tanks transfer recovered oil and water from portable tanks and bladders to vacuum trucks stationed on the pad. The vacuum trucks transfer the oil to CPF-1. The amount of oil is gauged using a Coliwasa tube or by other appropriate means. Liquids transported from the site to CPF-1 are manifested.	
(x) Plans, Procedures, and Locations for Temporary Storage and Disposal	The IMT prepares a waste management plan for submission to ADEC. The appropriate permits for waste storage and disposal are obtained. Oiled gravel and tundra are hauled to temporary lined containment cells near DS4 Grind & Inject facility. Disposal occurs at DS4 Grind & Inject facility. Non-liquid oily wastes are disposed of by classification. Oily wastes are stored in polybags and disposed of per the ADEC-approved waste management plan. Recovered fluids are transferred via vacuum truck to Kuparuk CPF-1, where the fluids are processed.	D-1 through D-5
(xi) Wildlife Protection Plan	Resources at risk are primarily water birds. The area is also known to be nesting grounds for Spectacled Eider and Brant birds. Exclusionary methods are implemented to keep oil away from bird habitat. Bird-hazing systems are deployed during open water season. Additionally, captive/treatment and stabilization are conducted as required. International Bird Rescue is deployed to make the wildlife treatment facility operational on Day 2. Portions of Kalub k Creek are anadromous. Trained and properly licensed personnel collect dead, oiled wildlife to reduce the risk of other wildlife preying on oiled carcasses.	W-1 through W-5
(xii) Shoreline Cleanup Plan	All shoreline activities are approved by the Unified Command. A Shoreline Task Force team is assembled to monitor Kalubik Creek; however, the plume does not reach shoreline.	

TABLE 1-10:
DS 2A-15 PRODUCTION WELL BLOWOUT IN SUMMER
FALLOUT DISTRIBUTION BY RECEIVING ENVIRONMENT

RECEIVING ENVIRONMENT	INITIAL AREA (sq ft)	INITIAL AREA (acres)	VOLUME (bbls)	RATE (bpd)	PERCENT (%)
Gravel Pad	56,651	1.3		405	75%
Tundra/Water	3,898,068	89.5		135	25%
Total:	**3,954,720**	**91**		**540**	**100%**

TABLE 1-11:
DS 2A-15 PRODUCTION WELL BLOWOUT DURING SUMMER
ON-PAD RECOVERY AND HANDLING CAPABILITY

A	B	C	D	E	F	H
TASK FORCE/ACS RECOVERY TACTIC	**NUMBER OF SYSTEMS**	**RECOVERY SYSTEM**	**OIL RECOVERY RATE (BPH OR CU YD/HR)**	**MOBILIZATION, DEPLOYMENT, AND TRANSIT TIME TO SITE (HOURS)**	**OPERATING TIME (HOURS IN A 24-HOUR SHIFT)**	**DURATION (DAYS)**
DAY 2 TO 15: RECOVERY OF LIQUIDS						
TF-2[A]: R-6, R-7	2	Vacuum truck recovery by direct suction.	77	1 Day[B]	20	14
					Target[C]:	
DAY 16 TO 23: RECOVERY OF OILED GRAVEL						
TF-7[D]: R-26	4	Front-end loader or backhoe and 4 dump trucks	21.3	After Well Control	20	7
					Target:	

Notes:

A. TF-2 (Tactics R-6 and R-7) liquid recovery rates are based on a distance of 15 road miles from the well to CPF-1. The time in transit, including load/unload time is 3.9 hours. The load time is calculated using an average pumping rate of 200 bph (summer rate). The assumed travel speed is 35 mph. Tactic L-6 inventory lists 18 vacuum trucks available on the North Slope with a minimum of 300-barrel capacity.

B. Recovery operations begin after safety protocols are established. Recovery assumed to begin on Day 2.

C. Target for on-pad liquid recovery discussed in Table 1-8 and Table 1-9.

D. TF-7 recovery rate is based on Tactic R-5. The recovery rate for gravel is based on the transit time of the dump truck:
Tc/(Lt+Tt+Ut) = 20 cubic yards (cu yd)/(0.25 hour + (60 miles to DS4 Grind & Inject* 2 trips/35 mph) + 0.08 hour) = 5.32 cu yd/hr, where
Tc = Truck Capacity, Lt = Load Time, Tt = Travel Time, Ut = Unload Time
With 4 dump trucks per task force, the effective recovery per TF5 unit is 4 x 5.32 cu yd/hr or 21.3 cu yd/hr.

E. The recovery operations are conducted on a non-emergency basis after well control is achieved. Recovery target for oiled gravel is discussed in Part vii.

TABLE 1-12:
DS 2A-15 PRODUCTION WELL BLOWOUT OFF-PAD RECOVERY CAPACITY, D

MER

A	B	C	D	E	F	H	J
TASK FORCE/ACS SPILL RECOVERY TACTIC	NUMBER OF SYSTEMS	RECOVERY AND HANDLING SYSTEMS	DERATED RECOVERY RATE[A] [bbl/hr]	MOBILIZATION AND TRANSIT TIME TO SITE [time]	OPERATING TIME ON DAY 1 [hr/day]	OPERATING TIME ON DAY 2[B] [hr/day]	OPERATING TIME ON DAYS 3-16[B] [hr/day]
TF-3: R-8	3	Action Drum/brush combination 24MD or comparable	20	24 hours	0	10	10
TF-3: R-8	2	Morris MI-30 disc skimmer or comparable	10	24 hours	0	10	10
TF-3: R-8	6	Rope mops (various brands)	3	24 hours	0	10	10
Recovery from tundra and ponds							
Maximum recovery target for tundra and ponds[C]							

Notes:

A. Recovery Rates for each task force include:
   TF-5 - Action Drum/Brush Combination 24MD skimmer is derated to 20% of the nameplate pumping rate: 20% x 100=20 bph
   TF-5 - The Morris MI-30 skimmer is derated to 10 bph
   TF-5 - Rope mops are derated to 20% of the nameplate pumping rate: 20% x 14=3 bph

B. As long as the task forces exceed the targeted recovery rate, operations are only conducted 10 hours per day. Most likely, recovery operations will be conducted intermittently over the entire day.

C. Target rates are discussed in Table 1-10.

TABLE 1-13:
DS 2A-15 PRODUCTION WELL BLOWOUT DURING SUMMER
LIQUID HANDLING CAPABILITY

A	B	H	I	J	K	L	M	N	O	P	Q
SPILL RECOVERY TACTIC, ACS TACTICS DESCRIPTION	NUMBER OF RECOVERY SYSTEMS PER TASK FORCE	DESCRIPTION	STORAGE CAPACITY VOLUME (bbl)	TARGET RATE X EMULSION RATE (bpd)[A]	TIME ON LOCATION PRIOR TO NEEDING OFFLOAD (days) I/J	OFF-LOADING MECHANISM	OFF-LOADING RATE (bph)	TRANSIT TIME - BOTH WAYS (hrs)	OFF-LOADING TIME (hrs) I/M	LOAD, OFF-LOAD, AND TRANSIT TIME (hrs) N+(Ox2)	PROJECTED HANDLING RATE[B] (bpd)
DAYS 2 TO 16: OFF-PAD RECOVERY OPERATIONS:											
TF-3: R-8	3	Drum/brush skimmer with three 2,400 gallon portable storage unit		225[A]	0.76	4-inch diesel trash pump	215	-	-	-	-
TF-3: R-8	2	Disc skimmer with two 2,400 gallon portable storage unit		225[A]	0.50	4-inch diesel trash pump	215	-	-	-	-
TF-3: R-8	6	Rope mops (various brands) with one 2,400 gallon portable storage unit		225[A]	0.25	4-inch diesel trash pump	215	-	-	-	-
DAYS 2 TO 16: OFF-PAD TO PAD TRANSFER:											
TF-4: R-23	1	Rolligon with 10,000-gallon trailer tanker		225[A]	0.27	4-inch diesel trash pump	215	2	1.1	4.2	1,190
DAYS 2 TO 16: PAD TO CPF-2 TRANSFER:											
TF-4: R-6	1	Vacuum truck		225[A]	0.34	Vacuum truck	200	0.3	1.5	3.3	1,820

Notes:

A. The Targeted Oil x Emulsion Recovery Rate is t l that is recovered off-pad x 1.67 (emulsion factor). For example, the off-pad fallout is 135 bpd, which requires 225 bpd of storage (135 bpd x 1.67 = 2 ed storage).

B. The projected handling rate of the Rolligon with based on five round trips a day multiplied by 238 barrels a trip (5 x 238 = 1,190 bpd) The projected handling rate of the vacuum truck able 1-11 (91 bph x 20 hrs = 1,820 bpd).

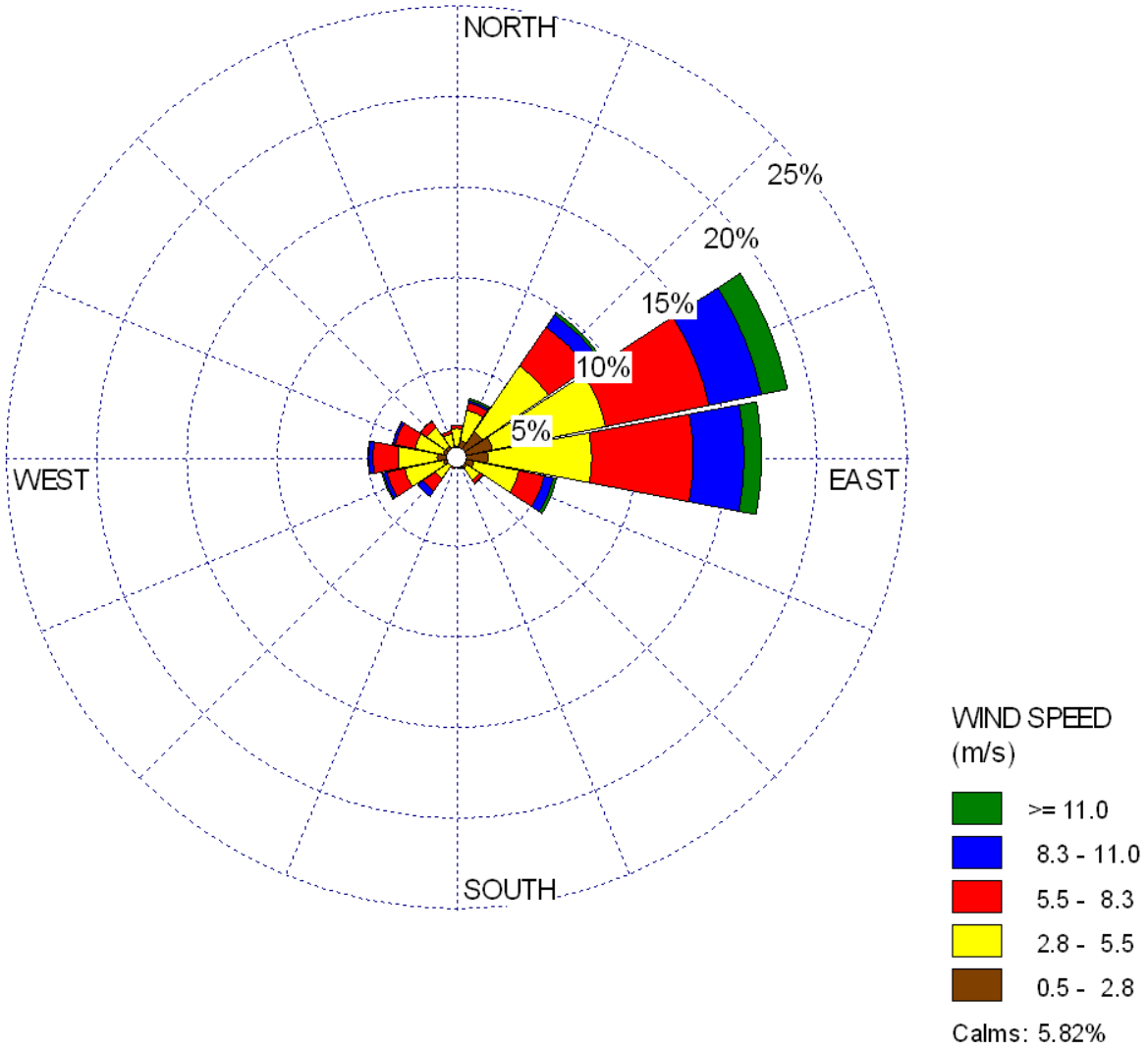
TABLE 1-14:
DS 2A-15 PRODUCTION WELL BLOWOUT DURING SUMMER OIL RECOVERY AND TRANSFER EQUIPMENT

CONTAINMENT AND RECOVERY EQUIPMENT	TASK FORCE	ACS TACTIC	MAXIMUM NUMBER OF ITEMS	NOTES
Vacuum Trucks				
	TF-2	R-6, R-7	2	1 per team
	TF-4	R-23, R-6	1	1 per team
		Subtotal:	**3**	
Rolligons with Trailer Tank				
	TF-4	R-23,R-6	1	1 per team
	TF-5	R-4	2	1 per team
2,400 Gallon Portable Storage Unit				
	TF-3	R-8	6	6 per Task Force
Dump Trucks				
	TF-7	R-26	16	4 per team
Front-End Loaders				
	TF-1	C-4	2	1 per team
	TF-7	R-26	4	1 per team
		Subtotal:	**6**	
Backhoes				
	TF-1	C-4	2	1 per team
Skid Steers				
	TF-1	C-4	2	1 per team
Water Truck				
	TF-5	R-4	2	1 per team
	TF-6	R-21	1	1 per team
		Subtotal:	**3**	
Trimmers				
	TF-7	R-26	4	1 per team

TABLE 1-15:
DS 2A-15 PRODUCTION WELL BLOWOUT DURING SUMMER STAFF FOR OPERATION OF OIL RECOVERY AND TRANSFER EQUIPMENT

CONTAINMENT AND RECOVERY OPERATORS	ACS TACTIC	NUMBER OF UNITS PER SHIFT				NOTES
		DAY 1	DAYS 2-15	DAY 16	DAYS 17-23	
TF-1	C-4	1	1	0	0	1 team leader per task force
TF-2	R-6, R-7	0	1	1	0	1 team leader per task force
TF-3	R-8	0	3	3	0	Shared
TF-4	R-23, R-6	0	1	1	0	1 team leader per task force
TF-5	R-5	0	0	1	1	1 team leader per task force
TF-6	R-21	0	0	1	0	1 team leader per task force
TF-7	R-26	0	0	0	1	1 team leader per task force
Sub-Total		**1**	**6**	**7**	**2**	
TF-1	C-4	4	4	0	0	
TF-2	R-6, R-7	0	2	2	0	1 per truck
TF-3	R-8	0	22	22	0	2 per skimmer
TF-4	R-26	0	1	1	0	1 per truck
TF-5	R-4	0	0	4	4	2 per team
TF-6	R-21	0	0	2	0	2 per team
TF-7	R-26	0	0	0	1	spotter
Sub-Total		**4**	**29**	**31**	**5**	
Total		**5**	**35**	**38**	**7**	
TF-1	C-4	2	2	0	0	Front-end loader
		2	2	0	0	Backhoe
		2	2	0	0	Skid steers
TF-2	R-6	0	2	2	0	1 per truck
TF-4	R-26	0	1	1	0	Rolligon with trailer tank
		0	1	1	0	Vacuum truck
TF-5	R-4	0	0	4	4	1 water truck and 1 Rolligon per team
TF-6	R-21	0	0	1	0	1 water truck per team
TF-7	R-26	0	0	0	16	Dump truck (4 trucks per team)
		0	0	0	4	Loader
		0	0	0	4	Trimmer
Sub-Total		**6**	**10**	**9**	**28**	

FIGURE 1-3:
KUPARUK SUMMER WIND ROSE DIAGRAM



Per convention, the wind rose illustrates direction of wind origin (i.e., where the wind is coming from).

FIGURE 1-4:
DS 2A-15 PRODUCTION WELL BLOWOUT DURING SUMMER

SCENARIO 2

KUPARUK DS 2A PAD

DS 2A-15 PRODUCTION WELL BLOWOUT DURING WINTER

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TABLE 1-16:
DS 2A-15 PRODUCTION WELL BLOWOUT DURING WINTER SCENARIO CONDITIONS

PARAMETER	PARAMETER CONDITIONS
Spill Location	Production well 2A-15 on DS 2A Pad
Date	February 15
Duration	15 days
Type of Spill	Uncontrolled, unobstructed well blowout through an open orifice (without assisted lift)
Quantity of Oil Spilled	
Emulsification Factor	Not applicable (All oil falls to snow/ice; no oil reaches open water.)
Oil Type	Alaska North Slope Crude
Wind Direction and Speed	Wind data are derived from the Kuparuk meteorological station (see Figure 1-5). The data used were collected during winter months (November through April) from November 2005 through April 2011. The predominant wind directions are WSW, W, and E. The mean wind speed is 10 knots. The relative percentages of these predominant winds are the following: • Day 1 through 5.7: wind from WSW (N112.5°W) • Day 5.8 through 10.5: wind from W • Day 10.6 through 15: wind from E
Current	Not applicable
Air Temperature	-20 F
Surface	Well location is on a gravel pad. Surrounding surface is frozen tundra and ice. Snow depth 0 to 36 inches; average 12 inches.
Trajectory	The simulated blowout is discharging at a rate of 540 bpd with a GOR of 6,382 scf/bbl through a 6.3-inch-diameter pipe. The SL Ross plume dispersion model published in ACS *Technical Manual* Tactic T-6 projects that the oil takes the form of an aerial plume extending from the well in the direction of the predominant wind directions. The model projects a gas flow of approximately 3.4 million scf of gas per day. The model predicts the following plume dimensions: • Approximately 80 percent of the discharged oil falls within 700 feet downwind of the well. At that distance, each fallout plume is about 137 feet wide. • Ninety percent of the discharged oil falls within 4,873 feet downwind of the well. At that distance, each fallout plume is about 786 feet wide. • According to the SL Ross model, 10 percent of discharged oil is in the form of droplets so small (50 micrometers or less) that they do not fall to the ground. As a conservative measure for response planning purposes, the volume of oil that is predicted to stay aloft is proportionally distributed between the two modeled fallout zones. Consequently, the scenario addresses the full RPS volume of 8,100 barrels. The distribution of the fallout plumes is detailed in Table 1-18. Approximately 5,400 barrels of the discharged oil falls on the pad. Oil falling on the pad is retained in gravel and snow, or accumulates in drainage basins. Berms and trenches are built, where appropriate, to help contain oil on and off the pad. Approximately 2,700 barrels of oil falls beyond the pad, impacting frozen, snow-covered tundra and ponds.

TABLE 1-17:
DS 2A-15 PRODUCTION WELL BLOWOUT DURING WINTER RESPONSE STRATEGY

ADEC REQUIREMENT	RESPONSE STRATEGY	REFERENCES TO THE ACS TECHNICAL MANUAL AND THIS ODPCP
(i) Stopping Discharge at Source	Efforts are made to bring the well under control. Emergency shutdown procedures are initiated. Once it has been determined control of the well cannot be immediately regained, or the safety of personnel is at risk, personnel are evacuated to pre-designated safe areas, with adequate shelter, minimal survival equipment, and communication equipment. At all times, the safety of personnel is the first concern. No unauthorized personnel are allowed near the spill area. The Wells Supervisor notifies the Wells Superintendent. All appropriate notifications are made. The IMT is activated. Wild Well Control is called at 1-281-784-4700. Wild Well Control is dispatched from Houston within 12 hours. Wild Well Control initiates attempts to stop the blowout by means of subsurface mechanisms. Surface methods control the blowout on Day 15.	Section 1.2 of this plan
(ii) Preventing or Controlling Fire Hazards	Throughout the first few hours of the spill, the Site Safety Officer verifies all sources of ignition are shut down or removed from the area. The Site Safety Officer provides access zone information and determines PPE requirements. Access to the spill site is carefully controlled and the scene is secured by Security. Monitoring protocol is established by the Site Safety Officer for all work areas to ensure personnel protection. The monitoring protocol establishes safety zones according to applicable OSHA and fire hazard standards based on current weather conditions and forecasts. Containment and recovery operations are allowed without respiratory protection in areas where safety criteria are met. Recovery operations and traffic are not allowed downwind of the blowout well in oiled areas where workers may become exposed to flash fire hazard or oil particulate matter at concentrations in excess of permissible exposure limits.	S-1 through S-6
(iv) Surveillance and Tracking of Oil	Blowout plume model is run. The extent of oil on the snow is delineated with stakes and global positioning systems so that it can be found if subsequent snowfall or blowing snow covers the spill.	T-6 T-1
(v) Exclusion Procedures	All oil falls to the surface and is absorbed into the snow. No open water is available. Initial cleanup efforts focus on any areas where oil falls on snow and ice covering river and lake environments and any other priority sites, removing oil and contaminated snow from those areas first.	Not applicable
(vi) Spill Containment and Control Actions	**Days 1 to 5.7** Upon initial reports of the blowout, ACS begins transportation of containment and recovery equipment from Deadhorse and other North Slope facilities to a staging area at Kuparuk West Sak 14. CPAI, in conjunction with ACS, begins activating the appropriate pre-approved permits needed for spill response operations. Containment and recovery operations begin after safety protocols are established. Work conducted near the blowout is carefully monitored for safety; no ignition sources are allowed in hot zones and proper PPE is required (see part ii above).	L-3 A-3

TABLE 1-17 (CONTINUED): DS 2A-15 PRODUCTION WELL BLOWOUT DURING WINTER RESPONSE STRATEGY

ADEC REQUIREMENT	RESPONSE STRATEGY	REFERENCES TO THE ACS TECHNICAL MANUAL AND THIS ODPCP
(vi) Spill Containment and Control Actions (continued)	**Task Force 1 (TF-1) – Containment** TF-1 consists of two skid steers and two loaders. On Day 2, TF-1 builds trenches and berms at strategic locations upwind and crosswind of the aerial plume in order to contain oil and control its movement into areas where recovery can occur. Trenches and berms are also used to separate pooled oil from vehicle access routes. The berms are raised/shored up on an ongoing basis, as needed. Sorbents are used as necessary. **Days 5.8 to 10.5 and 10.6 to 15** As the wind changes and shifts the orientation of the fallout plume toward the east then west, containment operations adjust accordingly. Berms and trenches contain oil flowing on and off the pad.	C-1, C-4
(vii) Spill Recovery Procedures	**Days 1 to 5.7** Equipment for the recovery, transfer, and interim storage of oiled snow and recovered oil are trucked to the staging area. Recovery begins once staging areas and safety protocols are established. Information on heavy equipment for the response is presented in Table 1-20. Lists of personnel for recovery operations are detailed in Table 1-21. Task forces focus on any areas where oil falls on snow and ice covering river and lake environments and any other priority sites, removing oil and contaminated snow from those areas first. **Task Force 2 (TF-2): Liquid Recovery** On Day 2, TF-2 mobilizes to the blowout site. Using three vacuum trucks, pumps, and hoses, TF-2 begins recovery of oil from the drainage basins and the bermed and trenched areas containing oil. Vacuum trucks are capable of recovering liquid oil up to 200 feet from the truck. The former reserve pit provides a natural containment area that is used for recovery. Recovery continues as the blowout continues and as long as conditions allow for safe operations. **Days 5.8 to 10.5 and 10.6 to 15** When the wind shifts, oiled snow removal equipment has access to the ENE and then E plume. Limited oiled-snow recovery occurs between Days 5.8 and 15. On Day 15, surface control is achieved, allowing full access to the oiled snow in all areas. **Task Force 3 (TF-3): Mechanized Snow Removal** TF-3 consists of a Tracked dozer, front-end loader or skid steers, 2 dump trucks (averaging 20 cubic yards) per strike team. Tactics R-1 and R-3 mechanical recovery rates are based on a distance of 20 road miles from the blowout site to storage/processing area (Kuparuk DS-1H or CPF-1). **Task Force 4 (TF-4): Manual Snow Removal** TF-4 consists of shovels, brooms, snow blowers, 3 snow machines or all-terrain vehicles (ATVs), front-end loader, and a dump truck. Tactic R-2 recovery rate is based on one six-man crew recovering 30 cubic yards in 10 hours. **Days 15 to 21** Day 15, surface control is achieved, allowing full access to the oiled snow. TF-3 and TF-4 increase the number of recovery systems to five teams each. The cumulative recovery capacity of TF-3 and TF-4 exceeds the capacity of oiled snow within the modeled blowout plumes.	L-2 R-6, R-7 R-1, R-3 R-1A, R-2
(viii) Lightering Procedures	Not applicable	Not applicable

TABLE 1-17 (CONTINUED): DS 2A-15 PRODUCTION WELL BLOWOUT DURING WINTER RESPONSE STRATEGY

ADEC REQUIREMENT	RESPONSE STRATEGY	REFERENCES TO THE ACS TECHNICAL MANUAL AND THIS ODPCP
(ix) Transfer and Storage of Recovered Oil/Water; Volume Estimating Procedure	Oiled liquids are loaded into vacuum trucks and transported to CPF-1, approximately 15 miles from the blowout site. Oiled snow is loaded into lined dump trucks for transport to the interim lined storage pits located at a suitable site within 15 to 20 road miles of the site. KRU DS-1H may be used for contaminated gravel and/or snow storage, and contains 12,230 cubic yards of storage capacity. CPF-1 is also within approximately 15 miles. Liner is available from multiple North Slope locations. Liquid levels in snow storage areas are monitored by on site personnel. When the oiled snow melts in the interim storage pits in the summer, oily liquids are hauled to the nearest off-spec oil and water recycle facilities for processing.	R-1, R-2, R-3, R-5 D-1, D-2, D-5
(x) Plans, Procedures, and Locations for Temporary Storage and Disposal	The IMT prepares a waste management plan for submission to ADEC. The appropriate permits for waste storage and disposal are obtained. Oiled gravel is loaded into lined dump trucks for transport to the interim lined storage pits located at a suitable site within 60 road miles of the site. KRU DS-1H or DS4 Grind & Inject are within 60 road miles. Gravel from DS-1H is thermally remediated each summer or every other summer, depending on volume requirements. Lined interim storage pits (10,000 sq ft each or larger) are constructed at suitable sites within the existing infrastructure. Storage pits may be constructed using construction timbers, 3 feet above grade, or by excavating a gravel containment area 3 feet below grade at a suitable site, using gravel spoils to construct 2-foot-perimeter berming. All storage areas are lined. Snow is piled 14 feet high. The storage pits are monitored until all contents have been processed. Oil recovered by vacuum trucks from the containment cells is taken directly to the CPF-1 for processing. Non-oily wastes are classified and disposed of accordingly.	D-1 to D-5 R-26
(xi) Wildlife Protection Plan	A wildlife task force deters birds and mammals from the oiled areas and interim storage pits. The wildlife stabilization center in Deadhorse is made operational and staffed by International Bird Rescue by Hour 24. No wildlife becomes oiled.	W-1, W-2A, W-5
(xii) Shoreline Cleanup Plan	Not applicable. No oil reaches shoreline.	Not applicable

TABLE 1-18:
DS 2A-15 PRODUCTION WELL BLOWOUT IN WINTER
FALLOUT DISTRIBUTION

RECEIVING ENVIRONMENT	INITIAL AREA (sq ft)	INITIAL AREA (acres)	VOLUME (bbls)	RATE (bpd)	PERCENT (%)
Frozen, snow-covered pad	7,290	0.2		360	67%
Frozen, snow-covered tundra	5,924,790	136		180	33%
Total:	**5,932,080**	**136**		**540**	**100%**

TABLE 1-19:
DS 2A-15 PRODUCTION WELL BLOWOUT DURING WINTER
STAFF FOR OPERATION OF OIL RECOVERY AND TRANSFER EQUIPME

A	B	C	D	E	F	H
SPILL RECOVERY TACTIC	NUMBER OF SYSTEMS	RECOVERY SYSTEM	OILED SNOW RECOVERY RATE [cu yd/hr or bbl/hr]	MOBILIZATION AND TRANSIT TIME TO SITE [time]	OPERATING TIME [hr/day]	TIME [days]
DAYS 2 TO 15: LIQUID RECOVERY						
TF-2: R-6, R-7	3	Vacuum trucks recover liquids from fast tanks and from ground. Liquids are transported to CPF-1.	60	See notes 1-2	20	14
DAYS 2 TO 15: LIMITED OILED SNOW RECOVERY (DURING BLOWOUT)						
TF-3: R-1, R-3	1	Mechanical Recovery: Tracked dozer, front-end loader or skid steer, 2 dump trucks (averaging 20 cu yd), sorbents	24	See notes 3-4	20	14
TF-4: R-1A, R-2	2	Manual Recovery: shovels, brooms, snow blowers, 3 snow machines or ATVs, front-end loader, dump truck	3.0	See notes 3, 5	20	14
DAYS 16 TO 23: OILED SNOW RECOVERY (POST BLOWOUT)						
TF-3: R-1, R-3	5	Mechanical Recovery: Tracked dozer, front-end loader or skid steer, 2 dump trucks (averaging 20 cu yd), sorbents	24	See notes 3-4	20	8
TF-4: R-1A, R-2	5	Manual Recovery: shovels, brooms, snow blowers, 3 snow machines or ATVs, front-end loader, dump truck	3.0	See notes 3, 5	20	8
DAY 17 TO 24: GRAVEL RECOVERY (POST BLOWOUT)						
TF-6: R-5, R-26	5	Recovery of Embedded Oil: trimmer, front-end loader, 4 dump trucks (averaging 20 cu yd)	21.3	See note 6	20	7

1. Mobilization completed at end of Day 1. TF-2 begins liquid recovery at beginning of Day 2.
2. TF-2 liquid recovery rates are based on a distance of 15 road miles from the well to CPF-1. The time in transit, including load/unload time, is 4.7 hours. The load time is calculated using an average pumping rate of 150 bbl/hr. The assumed travel speed is 35 mph. Tactic L-6 inventory lists 18 vacuum trucks available on the North Slope with a minimum 300-barrel capacity.
3. After the wind shifts on Day 7, limited oiled-snow recovery occurs. By the end of Day 15, full access to the oiled-snow plumes allows full recovery.
4. TF-3 (Tactics R-1 and R-3) mechanical recovery rates are based on a distance of 15 to 20 road miles from the blowout site to storage/processing area (Kuparuk DS-1H or CPF-1), 35 mph transit speed, 0.34 hr load time, 0.16 hr unload time, and an dump truck volume of 20 cubic yards. .
5. TF-4 (Tactic R-2) recovery rate based on one six-man crew recovering 30 cubic yards in 10 hours.
6. TF-6 (Tactics R-5, R-26) oiled gravel recovery rates are based on a distance of 60 road miles from the blowout site to DS4 Grind & Inject. Transit time includes loading, unloading, and time in transit round trip. A total of 3.4 hours transit time is required based upon a speed of 35 mph, 0.25 hr load time, and 0.08 hr unload time. Approximately 161 dump trucks are available for North Slope response (Tactic L-6, Table 9A). The average volume of the dump trucks is 20 cu yd.

TABLE 1-20:
DS 2A-15 PRODUCTION WELL BLOWOUT DURING WINTER
OIL RECOVERY AND TRANSFER EQUIPMENT

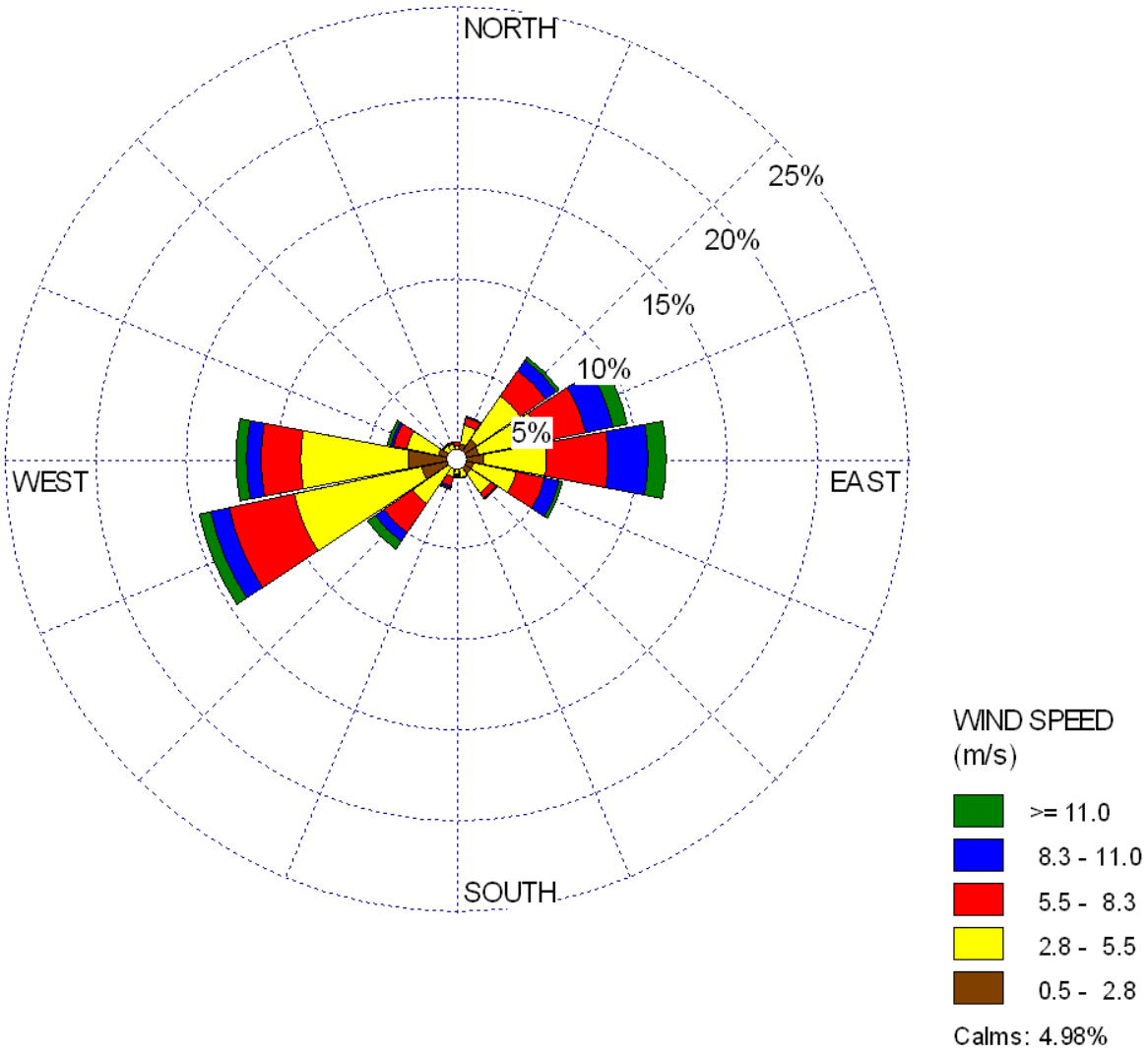
CONTAINMENT AND RECOVERY EQUIPMENT	TASK FORCE	ACS TACTIC	MAXIMUM NUMBER OF ITEMS	NOTES
Dump Trucks				
	TF-3	R-1, R-3	10	2 per unit
	TF-4	R-1A, R-2	3	0.5 per unit (shared)
	TF-6	R-5	15	3 per unit
		Subtotal:	**28**	
Front-End Loaders				
	TF-1	C-4	2	1 per unit
	TF-3	R-1, R-3	5	1 per unit
	TF-4	R-1A, R-2	3	0.5 per unit (shared)
	TF-6	R-5	5	1 per unit
		Subtotal:	**15**	
Tracked Dozers				
	TF-3	R-1, R-3	5	1 per unit
Snow Machines or ATVs				
	TF-4	R-1A, R-2	15	3 per unit
Snow Blowers				
	TF-4	R-1A, R-2	5	1 per unit
Skid Steers or Backhoes				
	TF-1	C-4	2	1 per unit
	TF-3	R-1, R-3	3	shared
		Subtotal:	**5**	
Trimmers				
	TF-6	R-5	5	1 per unit
Vacuum Trucks				
	TF-2	R-6, R-7	3	1 per unit
Water Truck				
	TF-5	R-5	2	1 per unit

TABLE 1-21:
DS 2A-15 PRODUCTION WELL BLOWOUT DURING WINTER
STAFF FOR OPERATION OF OIL RECOVERY AND TRANSFER EQUIPMENT

CONTAINMENT AND RECOVERY OPERATORS	ACS TACTIC	NUMBER OF UNITS PER SHIFT			NOTES
		DAY 1	DAYS 2-15	DAYS 16-24	
SKILLED TECHNICIANS					
TF-1	C-1, C-4	1	1	0	1 team leader per task force
TF-2	R-6, R-7	0	1	0	1 team leader per task force
TF-3	R-1, R-3	3	1	3	1 team leader per two strike teams
TF-4	R-1A, R-2	3	1	3	1 team leader per two strike teams
TF-5	R-21	0	0	1	1 team leader per task force
TF-6	R-5	0	0	1	1 team leader per task force
Sub-Total		**7**	**4**	**8**	
GENERAL TECHNICIANS					
TF-1	C-1, C-4	4	4	0	2 per team
TF-2	R-6, R-7	0	3	0	1 per team
TF-3	R-1, R-3	0	1	3	1 spotter per 2 teams
TF-4	R-1A, R-2	0	12	30	Shovel and broom recovery personnel (6 per unit)
TF-5	R-21	0	0	4	2 per team
TF-6	R-5	0	0	3	1 spotter per 2 teams
Sub-Total		**4**	**20**	**40**	
Total		**11**	**24**	**48**	
EQUIPMENT OPERATORS					
TF-1	C-1, C-4	2	2	0	Front-end loader
		2	2	0	Skid steers
TF-2	R-6, R-7	0	3	0	Vacuum truck
TF-3	R-1, R-3	0	2	10	Dump trucks (2 trucks per unit)
		0	1	5	Tracked dozers
		0	1	5	Loaders
		0	1	3	Skid steers (shared)
TF-4	R-1A, R-2	0	1	3	0.5 per unit (shared)
		0	1	3	0.5 per unit (shared)
		0	3	15	ATV or snow machine (3 per strike team)
TF-5	R-21	0	0	2	Water truck (1 per strike team)
TF-6	R-5	0	0	20	Dump truck (4 trucks per strike team)
		0	0	5	Loader
		0	0	5	Trimmer
Sub-Total		**4**	**17**	**76**	Most equipment operators are transporting recovered materials from release site.

Note:
Equipment operators are not necessarily North Slope Regional Response Team (NSRRT) certified.

FIGURE 1-5:
KUPARUK WINTER WIND ROSE DIAGRAM



Per convention, the wind rose illustrates direction of wind origin (i.e., where the wind is coming from).

FIGURE 1-6:
DS 2A-15 PRODUCTION WELL BLOWOUT DURING WINTER SCENARIO BLOWOUT PLUME

SCENARIO 3

CRUDE OIL PIPELINE RUPTURE OVER KUPARUK RIVER TO OPEN WATER

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TABLE 1-22:
SCENARIO CONDITIONS
CRUDE OIL PIPELINE RUPTURE OVER THE KUPARUK RIVER TO OPEN WATER

PARAMETER	PARAMETER CONDITIONS
Spill Location	Kuparuk River crossing
Date	Summer
Duration	Instantaneous
Type of Spill	Rupture of Kuparuk Pipeline
Quantity of Oil Spilled	
Emulsification Factor (for Storage Purposes)	1.67
Oil Type	Alaska North Slope Crude
Wind Direction and Speed	Wind data are derived from the Kuparuk meteorological station. The data used were collected during summer months (May through October) from May 2005 through October 2011. The predominant wind directions are ENE and E. The mean wind speed is 10 knots.
Current	2 knots
Air Temperature	51 F
Trajectory	Adjusted RPS volume moves downstream under influence of the current. Aerial observation tracks the leading edge of the oil. Situation Status Unit reports the following (see Figure 1-7 and Figure 1-8): **Oil Movement** Control Site / Nautical Miles / Oil Arrival (hr) CS#1 — 2.7 — 1.3 CS#2 — 2.8 — 1.3 CS#3 — 5.3 — 4 CS#4 — 5.5 — 4

TABLE 1-23:
RESPONSE STRATEGY
CRUDE OIL PIPELINE RUPTURE OVER THE KUPARUK RIVER TO OPEN WATER

ADEC REQUIREMENT	RESPONSE STRATEGY	REFERENCES TO THE ACS TECHNICAL MANUAL
(i) Stopping Discharge at Source	The automated electronic leak detection system sounds an alarm to the CPF-3 Control Room Board Operator. The Board Operator first evaluates the alarm to determine whether it can be explained by any operational occurrence. If there is no other explanation for the alarm, the Board Operator isolates all producers from the line and closes the main remote-operated valves. The Board Operator then notifies Security, the producers, and CPF-3 Facility Supervisor that a pipeline leak is indicated and the line is being shut down (as per the *Kuparuk Pipeline Operating Procedures Manual*).	A-1
(ii) Preventing or Controlling Fire Hazards	Throughout the first few hours of the spill, the Site Safety Officer verifies all sources of ignition are shut down or removed from the area. The Site Safety Officer provides access zone information and determines PPE requirements. Access to the spill site is carefully controlled, and the scene is secured by Security. Monitoring protocol is established by the Site Safety Officer for all work areas to ensure personnel protection. The Kuparuk Fire Department provides fire suppression at the rupture point and assists Safety with air monitoring.	S-2 to S-6
(iv) Surveillance and Tracking of Oil; Forecasting Shoreline Contact Points	Aerial observation tracks the leading edge of the oil. Situation Status Unit reports the following (see Figure 1-7 and Figure 1-8): **Oil Movement** Control Site / Nautical Miles / Oil Arrival (hr) CS#1 2.7 1.3 CS#2 2.8 1.3 CS#3 5.3 4 CS#4 5.5 4 The Surveillance Unit projects the leading edge to move with the current based on previous flow measurement studies, 2 knots for 3 miles, then 1 knot. It is predicted that the main current will carry oil into the right channel 2.25 miles north of Spine Road. Tracking buoys are staged at the mouth of the river in the event they are needed to track oil entering Gwydyr Bay.	T-4 ACS *Technical Manual*, Volume 2, Map Atlas, Sheets 61, 63 and 69 L-6 T-5
(v) Exclusion Procedures	There are no priority protection sites between the rupture and the Kuparuk River delta. The nearest priority protection sites are approximately 8 miles north-northeast, adjacent to the delta. Resource agencies identify areas of concern upstream of the Kuparuk River delta, based on the priority protection sites listed in the ACS *Technical Manual,* Volume 2 Map Atlas.	W-6 ACS *Technical Manual*, Volume 2
(vi) Spill Containment and Control Actions	**Staging Area and Forward Command Post:** On the northwest side of the Kuparuk River Bridge, the SRT sets up a staging area at KUP-2.	L-2

TABLE 1-23 (CONTINUED): RESPONSE STRATEGY CRUDE OIL PIPELINE RUPTURE OVER THE KUPARUK RIVER TO OPEN WATER

ADEC REQUIREMENT	RESPONSE STRATEGY	REFERENCES TO THE ACS TECHNICAL MANUAL
(vi) Spill Containment and Control Actions, **(vii) Spill Recovery Procedures,** **(viii) Lightering Procedures** **and** **(ix) Transfer and Storage of Recovered Oil/Water; Volume Estimating Procedure**	**Control Site #1, WOA-1.** Southwest of the Kuparuk River bridge, responders maintain the 3,300-foot pre-deployed delta boom. The boom directs oil into the deadarm southwest of the bridge. Vacuum trucks remove the oil with skimmers. Vacuum trucks transit 2 miles to GC2.	C-7, C-8, R-6 D-1
	Control Site #2, KUP-2. North of the bridge, responders deploy pre-staged boom which directs oil to vacuum trucks. Vacuum trucks remove liquids from the containment booms and transfer the liquids to GC2.	C-8, R-6, D-1
	Control Site #3. Upstream of the channel fork, the responders maintain the 2,000-foot pre-deployed delta boom that deflects oil toward skimmers on the west side of the river. The teams also deploy long-skirt, high-flotation delta-type containment/deflection boom immediately downstream and recover oil with skimmers into Fastanks. KUP-4 pre-staged equipment is transported by tundra travel vehicles. Airboats haul equipment from KUP-2 and KUP-4. A Rolligon hauls stored liquids along a pre-established trail from Fastanks to vacuum trucks on the north side of R pad. The vacuum trucks carry the liquids 2 miles to GC2.	C-8, R-8, R-22, R-23, D-1
	Control Site #4. The responders deploy four 1,000-foot sections of boom to deflect oil into a deadarm. Skimmers in the deadarm recover the immobile oil into Fastanks. A second Rolligon hauls liquids from Fastanks to vacuum trucks on the north side of R pad. The vacuum trucks carry the liquids 2 miles to GC2.	C-8, R-7, R-8, R-22 R-23, D-1
	Offshore. As a contingency, ACS technicians transport boom and skimmer equipment to Simpson Lagoon adjacent to the Kuparuk River. The task force patrols the delta area and stands by to recover oil.	R-17
(x) Plans, Procedures, and Locations for Temporary Storage and Disposal	The IMT prepares a waste management plan for submission to ADEC. The appropriate permits for waste storage and disposal are obtained.	D-1
	Recovered oil is transferred to the Hydrocarbon Recycle Facility at GC2 for recycling. Alternative sites include CPF-1 and Pump Station 1.	D-2
	Non-liquid oily wastes are classified and disposed of according to classification. Sorbent material, Visqueen, and other materials are contained in polybags and disposed of according to the ADEC-approved waste management plan.	D-3
	Non-oily wastes are classified and disposed of accordingly.	D-4
(xi) Wildlife Protection Plan	A Wildlife Task Force excludes birds and mammals from entering oiled areas onshore and on water. The wildlife stabilization and treatment center at U8 is made operational on Day 1, and staffed by International Bird Rescue by Hour 24. No oiled animals are encountered.	
	The wildlife protection strategy is implemented.	W-1
	Wildlife hazing teams are deployed.	W-2A, W-2B
	The wildlife stabilization center is made operational.	W-5
	As oiled wildlife is identified, capture teams are deployed to the spill area.	W-3
(xii) Shoreline Cleanup Plan	Shoreline cleanup operations are initiated once the source of the oil has been stopped based on a plan approved by Unified Command. A shoreline assessment is conducted to understand the nature and extent of oiling. Based on shoreline assessment, priorities are established for cleanup. Cleanup techniques chosen are based on shoreline type and degree of oiling.	SH-1
	The following discussion is based on a speculative prediction of shoreline impact and is presented for illustrative purposes only. Prior to shoreline cleanup operation, the affected areas are surveyed to determine the appropriate response. Specific cleanup techniques are based on field data obtained at the time on shoreline habitats, type, and degree of shoreline contamination and spill-specific physical processes. It is not possible to presuppose the outcome of the Shoreline Cleanup and Assessment Technique (SCAT) process and/or the decisions of the Unified Command.	SH-2 through SH-11

TABLE 1-23 (CONTINUED):
RESPONSE STRATEGY
CRUDE OIL PIPELINE RUPTURE OVER THE KUPARUK RIVER TO OPEN WATER

ADEC REQUIREMENT	RESPONSE STRATEGY	REFERENCES TO THE ACS TECHNICAL MANUAL
(xii) Shoreline Cleanup Plan (continued)	Primary shoreline cleanup includes the following techniques: • Passive recovery with sorbents and cutting oiled vegetation. • Natural recovery for those areas where residual staining remains, but where further recovery would cause more harm than good. Oiled areas are cleaned up to the satisfaction of the Unified Command. Shoreline gravel is approached over land and by airboat and treated in place. Low-pressure flooding lifts oil for recovery. Oil and oiled materials are also recovered manually. Freighter airboats recover free oil into tanks on deck. Areas are monitored for the rest of the summer and the following summer under a plan approved by ADEC.	SH-7 SH-2 SH-3 SH-5

TABLE 1-24:
LIQUID RECOVERY CAPACITY
CRUDE OIL PIPELINE RUPTURE OVER THE KUPARUK RIVER TO OPEN WATER

A	B	C	D	E	F	G
SPILL RECOVERY TACTIC, ACS TECHNICAL MANUAL TACTIC	**NUMBER OF SYSTEMS**	**RECOVERY SYSTEM/SKIMMER NAME AND MODEL**	**OIL RECOVERY RATE PER SYSTEM (boph)**	**MOBILIZATION, DEPLOYMENT AND TRANSIT TIME TO SITE (hrs)**	**OPERATING TIME (hours per 24-hour shift)**	**LIQUID RECOVERY CAPACITY (bbl per day) (B x D x F)**
CS#1: R-6	14	Vacuum truck with Manta Ray	29*	1.9	20	
CS#2: R-6	9	Vacuum truck with Manta Ray	29*	1.9	20	
CS#3: R-8	4	V koma 30K disc	10	4	20	
CS#4: R-8	3	MI 30 disc	10	4	20	
Offshore: R-17	1	Desmi 250 (Ocean)	125	6	20	

*Oil recovery rate is adjusted by dividing a vacuum truck tank capacity by the period of its load-unload cycle, as follows:
[300 bbl vacuum truck capacity] / [(4-mile round trip / 35 mph)+(300 bbl / 200 boph offload)+(300 bbl / 34 boph oil loading)] = 28.8 boph

TABLE 1-25:
LIQUID HANDLING CAPABILITY
CRUDE OIL PIPELINE RUPTURE OVER THE KUPARUK RIVER TO OPEN WATER

A	H	I	J	K	L	M	N	O	P	Q
SPILL RECOVERY TACTIC, ACS TECHNICAL MANUAL TACTICS	NUMBER OF STORAGE SYSTEMS	STORAGE CAPACITY DESCRIPTION	STORAGE CAPACITY VOLUME (bbl)	MAXIMUM OIL / EMULSION AVAILABLE (bph)[1]	TIME ON LOCATION PRIOR TO NEEDING TO OFFLOAD (hrs) (J/K)	OFF-LOADING MECHANISM	OFF-LOADING RATE (bph)	TRANSIT TIME - BOTH WAYS (hrs)	OFFLOADING TIME (hrs) (J/N)	OFFLOAD AND TRANSIT TIME (hrs) (O+P)
CS#1: R-6,	14	Vac trucks		627	6.7	Vac Trucks	2,800	0.1	1.5	1.6
CS#2: R-6	9	Vac trucks		176	15	Vac Trucks	1800	0.1	1.5	1.6
CS#3: R-8	8	Fastanks		55	17	Tank Trailer	485	1	1.2	2.2
CS#4: R-8	6	Fastanks		41	17	Tank Trailer	485	1	1.2	2.2
Offshore: R-17	1	Mini barge		0	NA	Lightering R-28	628	not applicable	not applicable	not applicable

1. The maximum volume of oil/emulsion availa s the recovered oil that discharges to water x 1.67 (emulsion factor). Stranding is ignored in this column.

FIGURE 1-7:
KUPARUK PIPELINE RIVER CROSSING RUPTURE SUMMER SCENARIO
RUPTURE POINT

FIGURE 1-8:
KUPARUK PIPELINE RIVER CROSSING RUPTURE

SCENARIO 4

CPF-2 DIVERT TANK RUPTURE DURING SUMMER

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TABLE 1-26:
SCENARIO CONDITIONS
CPF-2 DIVERT TANK RUPTURE DURING SUMMER

PARAMETER	PARAMETER CONDITIONS
Spill Location	Kuparuk CPF-2, Tank T1-P201B
Date	August 1
Duration	Instantaneous
Type of Spill	Catastrophic tank rupture
Quantity of Oil Spilled	
Emulsification Factor (Applicable to oil that reaches open water, for storage purposes)	1.67
Oil Type	Alaska North Slope Crude
Wind Direction and Speed	Wind data are derived from the Kuparuk meteorological station. The data used were collected during summer months (May through October) from May 2005 through October 2011. The predominant wind directions are ENE and E. The mean wind speed is 10 knots.
Current	Not applicable
Air Temperature	51 F
Surface & Trajectory	Tank is located within a secondary containment berm. Although the majority of the containment structure remains intact, the force of the sudden release breaks down a section of the gravel dike and liner, and approximately 22,000 barrels escape the containment on the east side. Significant quantities of oil are retained by the gravel pad and tundra surfaces (see above).

TABLE 1-27:
RESPONSE STRATEGY
CPF-2 DIVERT TANK RUPTURE DURING SUMMER

ADEC REQUIREMENT	RESPONSE STRATEGY	REFERENCES TO THE ACS TECHNICAL MANUAL
(i) Stopping Discharge at Source	The entire contents of the east divert tank are lost. The immediate objective is to stabilize the weakened area of the berm and prevent the further escape of oil from the containment area. To prevent additional oil from entering the tank, the loading line is blocked and the divert pump is tagged and locked out.	Not applicable
(ii) Preventing or Controlling Fire Hazards	Throughout the first few hours of the spill, the Site Safety Officer verifies all sources of ignition are shut down or removed from the area. The Site Safety Officer provides access zone information and determines PPE requirements. Access to the spill site is carefully controlled, and the scene is secured by Security. Monitoring protocol is established by the Site Safety Officer for all work areas to ensure personnel protection. The CPF-2 Supervisor immediately shuts down all nearby flare systems. The North Slope Emergency Response Chief is on the scene with equipment and manpower to suppress the threat of an explosion. Throughout the first few hours of the spill, the Emergency Response Chief verifies all sources of ignition are shut down or removed from the area.	S-1 through S-6
(iii) Well Control Plan	Not applicable	Not applicable
(iv) Surveillance and Tracking of Oil	The SRT delineates the perimeter of oiling on the gravel pad and tundra. Extent of the oiling on the surface of the tundra pond is monitored using FLIR performed by the Twin Otter.	T-1, T-2 T-4
(v) Exclusion Procedures	No priority protection sites are identified. The drainage slough at the north end of the tundra pond is boomed to prevent runoff to the north. Utilidors on the CPF-2 pad are blocked to prevent further spread of oil to the western portions of the pad.	Volume 2, Map Atlas, Sheet 53 C-14 (1) C-4 (1)
(vi) Spill Containment and Control Actions **and** **(vii) Spill Recovery Procedures**	A staging area is established at CPF-2. TF-1 is a containment team working on and around the pad using gravel, sandbags, and Visqueen to shore up the containment area, block culverts, utilidors, etc. in order to limit any further oil from draining off the pad. TF-2 utilizes vac trucks to pump free oil from the secondary containment area and from pad depressions. TF-3 flushes low-pressure water over the tundra, moving oil down to collection points along the shore of the tundra pond. Sorbent fences are built to help contain runoff. TF-4 deploys containment boom at the drainage slough on the north end of the pond to prevent further movement of oil out of the pond to the north, and along the western shore of the pond to contain oil flushed down from the tundra by TF3. TF-5 is a containment and recovery task force deployed along the western shore of the tundra pond to recover oil collecting in booms from the TF3 tundra-flushing operations. TF-6 consists of five containment and recovery teams deployed along the north and east edges of the pond. Airboats and wash pumps are used to move oil into containment hook booms. Recovered oil is pumped from Fastanks via hoses and pumps in series to vac trucks located at CPF-2 and along the DS-2F access road. TF-7 is deployed to the drainage slough on the north edge of the tundra pond. Sorbents are used to recover the small amounts of oil that drained into the slough.	L-2 C-3, C-4 R-6 R-4, R-9 C-14 R-8, R-24 R-16, R-24 R-9

TABLE 1-27 (CONTINUED): RESPONSE STRATEGY CPF-2 DIVERT TANK RUPTURE DURING SUMMER

ADEC REQUIREMENT	RESPONSE STRATEGY	REFERENCES TO THE ACS TECHNICAL MANUAL
(vi) Spill Containment and Control Actions and (vii) Spill Recovery Procedures (continued)	TF-8 consists of small skiffs arranged in a J-boom configuration using sorbent boom to remove oil/sheen from the pond surface. SCAT teams survey the areas of tundra impact and delineate areas where burning of pooled oil and oiled vegetation is preferred over mechanical recovery methods so tundra damage from equipment and personnel movement can be minimized. TF-9 is an in situ burn unit deployed to areas delineated by SCAT. Once the pooled oil is recovered from the pad surfaces, TF-10 begins cleanup of the pad and its structures. Approximately 200,000 square feet of pad surface are saturated with oil. After the surface structures have been cleaned, approximately 22,222 cubic yards of contaminated gravel are removed.	R-17 w/R-9 B-1, B-2, B-5 R-21 (1) R-26 (1)
(viii) Lightering Procedures and (ix) Transfer and Storage of Recovered Oil/Water; Volume Estimating Procedure	A Fluid Transfer Task Force is established at CPF-2. Fluids are received by vac truck and directly from shore-based Fastanks via hoses and pumps in series. All recovered liquids are processed directly into CPF-2.	R-22
(x) Plans, Procedures, and Locations for Temporary Storage and Disposal	The IMT prepares a waste management plan for submission to ADEC. Temporary storage facilities are established at CPF-2. Contaminated soils and oily wastes are characterized and disposed of accordingly. Recovered fluids are processed directly into CPF-2. Contaminated gravel is transported to DS-1H for treatment.	D-1 through D-5
(xi) Wildlife Protection Plan	Resources at risk are primarily birds. Exclusionary methods are implemented to keep oil away from bird habitat. Additionally, hazing operations are initiated and captive/treatment and stabilization are conducted as required. International Bird Rescue is deployed to make the wildlife treatment facility operational on Day 2.	W-1 Through W-5
(xii) Shoreline Cleanup Plan	Shoreline cleanup operations are initiated once the source of the oil has been stopped based on a plan approved by Unified Command. A shoreline assessment is conducted to understand the nature and extent of oiling. Based on shoreline assessment, priorities are established for cleanup. Cleanup techniques chosen are based on shoreline type and degree of oiling.	SH-1 SH-2 through SH-11

TABLE 1-28:
LIQUID RECOVERY CAPABILITY
CPF-2 DIVERT TANK RUPTURE DURING SUMMER

A	B	C	D	E	F	G
SPILL RECOVERY TACTIC, ACS TECHNICAL MANUAL TACTIC	**NUMBER OF SYSTEMS**	**RECOVERY SYSTEM/SKIMMER NAME AND MODEL**	**DERATED OIL RECOVERY RATE PER SYSTEM (boph)**	**MOBILIZATION, DEPLOYMENT AND TRANSIT TIME TO SITE (hours)**	**OPERATING TIME (hours per 24-hour shift)**	**FLUID RECOVERY CAPACITY (bbl per day) (B x D x F)**
TF-1 (C-3; C-4)	Containment only.					
TF-2 (R-6)	2	Vac truck	73.9[1]	2.5	20	
TF-3 (R-4; R-9)	Flushing only. See TF-5 below for recovery.					
TF-4 (C-14)	Containment only.					
TF-5 (R-8)	6	Brush/drum skimmer	20	6	20	
TF-6 (R-16)	5	Disc skimmer	10	6	20	
TF-7 (R-9)	Passive recovery with sorbents only.					
TF-8 (R-17 w/R-9)	Passive recovery with sorbents only.					

1. Recovery rate includes transit and offload time to CPF-2 processing.

TABLE 1-29:
LIQUID HANDLING CAPABILITY
DIVERT TANK RUPTURE DURING SUMMER

A	B	H	J	K	L	M	N	O	P
SPILL RECOVERY TACTIC, ACS TECHNICAL MANUAL TACTIC	NUMBER OF SYSTEMS	STORAGE CAPACITY DESCRIPTION	OIL & EMULSION AVAILABLE (bph)[1]	TIME ON LOCATION PRIOR TO NEEDING TO OFFLOAD (hrs) (I/J)	OFF-LOADING MECHANISM	OFF-LOADING RATE (bph)	TRANSIT TIME - BOTH WAYS (hrs)	OFFLOADING TIME (hrs) (I/M)	OFFLOAD AND TRANSIT TIME (hrs) (N+O)
TF-2 (R-6)	2	Vac truck	458[2]	0.66	Vac trucks transfer recovered oil directly into CPF-2 West Tank				
TF-5 (R-8)	1	Fastanks (3)	see note 3 below		Hoses and pumps (R-24)	215	Continuous offloading directly to CPF-2		
TF-6 (R-16)	5	Fastanks (5)	70	4.3	Hoses and pumps (R-24) to vac trucks	215	Vac trucks continuously transfer oil directly into CPF-2 West Tank		
TF-6	5	Vac trucks	215	1.4	Vac trucks transfer recovered oil directly into CPF-2 West Tank				

1. The total volume of oil/emulsion available for recovery is the volume of oil that discharges to water x 1.67 (emulsion factor). The amount available per hour is equal to the total oil/emulsion available divided by 72 hours.
2. Oil in the containment dike does not emulsify.
3. The amount and rate of oil available for recovery are dependent on efficacy of tundra flushing operations. At 70 percent effectiveness, up to 11,633 barrels could be recovered.

FIGURE 1-9:
KUPARUK RIVER UNIT TANK RUPTURE SCENARIO

RESPONSE STRATEGY

DS-3R PRODUCTION WELL BLOWOUT DURING SUMMER

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TABLE 1-30:
DS-3R PRODUCTION WELL BLOWOUT DURING SUMMER SCENARIO CONDITIONS

PARAMETER	PARAMETER CONDITIONS
Spill Location	Kuparuk DS-3R
Date	August 1
Duration	15 days
Type of Spill	Uncontrolled well blowout open orifice
Oil Type	Alaska North Slope Crude
Wind Direction and Speed	Wind data are derived from the Kuparuk meteorological station (see Figure 1-3). The data used were collected during summer months (May through October) from May 2005 through October 2011. The predominant wind directions are ENE and E. The mean wind speed is 10 knots. The relative percentages of these predominant winds are the following: • Day 1 through 8: wind from ENE (N67.5°E) • Day 8 through 15: wind from E
Current	Not applicable
Air Temperature	51 F
Surface	Well location is a gravel pad; well is 200 feet from the pad edge. Open water (Simpson Lagoon) is approximately 300 feet east and 800 feet north of the pad edge. Tundra and tundra lakes comprise the landscape south and west of the pad.
Trajectory	The SL Ross plume dispersion model published in ACS *Technical Manual* Tactic T-6 projects that the oil takes the form of an aerial plume extending from the well in the direction of the predominant wind directions. Using the SL Ross model and the predominant winds, the fallout would occur in two plumes W and WSW of well Kuparuk DS-3R. As a conservative measure for response planning purposes, the trajectory descr bed in this strategy is assumed to fall directly into the Beaufort Sea.

TABLE 1-31:
RESPONSE STRATEGY
DS-3R PRODUCTION WELL BLOWOUT DURING SUMMER

ADEC REQUIREMENT	RESPONSE STRATEGY	REFERENCES TO THE ACS TECHNICAL MANUAL TACTIC AND THIS ODPCP
(i) Stopping Discharge at Source	Efforts are made to bring the well under control. Emergency shutdown procedures are initiated. Once it has been determined that control of the well cannot be immediately regained, or the safety of personnel is at risk, personnel are evacuated to pre-designated safe areas with adequate shelter, minimal survival equipment, and communication equipment. At all times, the safety of personnel is the first concern. No unauthorized personnel are allowed near the spill area. The well continues to blow out. The On-Site Company Representative notifies the Wells Superintendent. All appropriate notifications are made. The IMT is activated. The On-Site Company Representative calls Wild Well Control well control representatives at 1-281-784-4700. Wild Well Control is dispatched from Houston within 12 hours. Wild Well Control initiates attempts to stop the blowout using the appropriate well control methods. Surface methods control the blowout on Day 15.	Section 1.2 Table 1-2, Section 1
(ii) Preventing or Controlling Fire Hazards	Throughout the first few hours of the spill, the Site Safety Officer verifies all sources of ignition are shut down or removed from the area. The Site Safety Officer provides access zone information and determines PPE requirements. Access to the spill site is carefully controlled, and the scene is secured by Security. Monitoring protocol is established by the Site Safety Officer for all work areas to ensure personnel protection. This monitoring protocol will establish personnel and equipment safety zones according to applicable OSHA and fire hazard standards. Containment and recovery operations are allowed without respiratory protection in areas where safety criteria are met. Recovery operations are not allowed downwind of the blowout well in areas where workers may become exposed to flash fire hazard or oil particulate matter at concentrations in excess of permissible exposure limits.	S-1 Through S-6
(iii) Surveillance and Tracking of Oil	A blowout plume model is run using conditions observed at the site. Oil movement is tracked using a combination of visual observation and remote sensing techniques. Tracking buoys are deployed in Simpson Lagoon. The Twin Otter performs aerial surveillance of oil on water using FLIR. Vector addition and trajectory modeling are used to forecast oil movement.	T-6 T-4 T-2 T-5
(iv) Exclusion Procedures	Potential oil impact areas and priority protection sites are identified downstream of the Kuparuk facilities in Simpson Lagoon: Shoreline Protection Task Forces are deployed to Simpson Lagoon to the following priority protection sites: Priority Site # / Map Atlas / Boom Length (ft) / Tactic / Task Force 24A / 36 / 4,500 / C-14 / SPTF#1 25 / 35 / 1500 / C-14 / SPTF#1 27 / 35 / 100 / C-14 / SPTF#2 Boom is pre-staged at DS-3R and Oliktok Dock, decreasing the response time. A Shoreline Task Force member helps direct response workers away from the cultural sites, based on a shoreline cleanup plan approved by the Unified Command and the State Historic Preservation Officer.	C-14 Volume 2, Map Atlas, Sheets 35 and 36

TABLE 1-31 (CONTINUED):
RESPONSE STRATEGY
DS-3R PRODUCTION WELL BLOWOUT DURING SUMMER

ADEC REQUIREMENT	RESPONSE STRATEGY	REFERENCES TO THE ACS TECHNICAL MANUAL TACTIC AND THIS ODPCP
(v) Spill Containment and Control Actions and **and** **(vi) Spill Recovery Procedures**	**Day 1** Staging areas are established at Oliktok Dock and Ol ktok Point Staging Area. Containment and recovery operations begin after safety protocols are established. Work conducted near the blowout is carefully monitored for safety; no ignition sources are allowed in hot zones and proper PPE is required (see part ii above).	L-2
	Days 2 to 15 Generally, containment and recovery operations occur crosswind and upwind of the fallout plume. As the wind shift changes the direction of the plume fallout, containment and recovery crews are deployed to recover oil as follows:	
	• Anticipating pad drainage, Task Force 1 (TF-1) begins construction of oil containment berms and trenches crosswind and upwind of the blowout. To minimize runoff spread, TF-1 blocks the culverts under the pad and Oliktok roads.	C-4
	• Task Force 2 (TF-2) mobilizes to the blowout site. Using vacuum trucks, pumps, and hoses, TF-2 begins recovery of oil from the drainage basins and the bermed and trenched areas containing oil. Vacuum trucks are capable of recovering liquid oil up to 200 feet from the truck. However, recovery may be limited due to the inability for vacuum trucks to travel on Oliktok Road.	R-6, R-7
	• The Nearfield Task Force (TF-3) is an on-water containment and recovery system deployed within 12 hours of the blowout. TF-2 targets the leading edge of the oil that has reached the water, where oil particulate concentrations are below health and safety levels and in water of sufficient depth.	R-20
	• The Farfield Task Force (TF-4) deploys one skimming system targeting scattered windrows of oil that fell into the water during the first 12 hours downwind of the Nearfield Task Force. Together, TF-3 and TF-4 target all discharged oil deposited to the sea. TF-3 and TF-4 move beyond the nearshore shallows as necessary. The fallout plume is subjected to a westward current. Mini barges store the oil emulsion; consequently no intermediate storage barge is mobilized.	R-17
	• TF-5 is an onshore task force assigned to contain and recover oil that may escape the on-water task forces blowing back towards the shoreline over shallow water. Hook-boom recovery operations are spaced along impacted shoreline. The recovery and storage sites are accessed from pads and roads with road vehicles and along the shoreline and over tundra with tundra travel vehicles. Onshore task forces use Oliktok Point Staging Area and travel to recovery and containment sites under ACS emergency tundra travel permits.	R-16, R-24

TABLE 1-31 (CONTINUED): RESPONSE STRATEGY DS-3R PRODUCTION WELL BLOWOUT DURING SUMMER

ADEC REQUIREMENT	RESPONSE STRATEGY	REFERENCES TO THE ACS TECHNICAL MANUAL TACTIC AND THIS ODPCP
(vi) Spill Recovery Procedures (continued)	• TF-6 is an onshore task force deployed to the area between the pad and the shoreline. Sorbent fences are built upgradient of marsh fringes to keep oil out of the marsh areas. Drum skimmers and rope mops are used as necessary. Access is provided by plywood walkways.	C-4, R-8, R-9, R-24
	• TF-7 consists of Rolligons with trailer tanks. TF-7 collects recovered fluids from TF-5 and TF-6 and transfers them to vacuum trucks. Vacuum trucks transfer the fluids to CPF-1.	R-23
	• TF-8 is an onshore task force with the objective of protecting the large salt marsh located northwest of the pad (on the west side of Oliktok Road). Sorbent fences are constructed along the south edge of the marsh, in the path of expected drainage from the blowout plume, and recover a portion of the oil.	R-9, Volume 2, Map Atlas Sheet 35
	After Day 15	
	TF-1 and TF-2 maintain operations only as long as they are needed for liquid recovery.	R-6, R-7
	TF-3, TF-4, and TF-5 continue recovery operations as necessary.	R-20, R-17
	TF-6, onshore recovery team targeting oil between the pad and shoreline, increases number of strike teams significantly. With full access to the fallout area, recovery efforts are maximized in order to recover discharged oil by Day 18.	C-4, R-8, R-9, R-24
	TF-7 increases transport capability to match recovery rate of TF-5 and TF-6.	R-23
	TF-9 begins the process of flushing standing oil from the tundra surface. TF-9 strike teams consist of a water truck operator and two general technicians. The tundra is flushed with water and oil is recovered by hand using sorbent materials. Plywood walkways are used to minimize traffic damage to the tundra.	R-4
	TF-10: Once the blowout has been controlled, TF-10 begins cleanup of the pad and its structures. After the surface structures have been contaminated gravel is excavated and removed with Supersuckers, backhoes, skid steers, and dump trucks.	R-21, R-5
(vii) Lightering Procedures and (viii) Transfer and Storage of Recovered Oil/Water; Volume Estimating Procedure	Offloading pump transfer stored oil emulsion and water from mini barges to 60-barrel Fastanks at Oliktok Dock. Fastanks are pre-staged at Oliktok Dock and hauled from Kuparuk spill response warehouse on Day 1. On Day 16, vac trucks haul the Fastank contents to CPF-1. Offloading at other sites distal from the blowout site is considered. Liquids transported from Oliktok to CPF-1 are manifested.	R-28
	Rolligons transfer recovered fluids from temporary storage at TF-5 and TF-6 sites to vacuum trucks on Oliktok Road. Vacuum trucks transport recovered liquids from to CPF-1.	R-23
(ix) Plans, Procedures, and Locations for Temporary Storage and Disposal	A waste management plan is prepared for submission to ADEC. Oiled gravel and tundra are hauled to DS4 Grind & Inject facility. Non-liquid oily wastes are disposed of by classification. Oily wastes are disposed of per the ADEC-approved waste management plan. Recovered fluids are transferred via Rolligon and vacuum truck to CPF-1, where the fluids are processed.	D-1 through D-5
(x) Wildlife Protection Plan	Resources at risk are primarily birds. Exclusionary methods are implemented to keep oil away from bird habitat. Additionally, hazing operations are initiated and captive/treatment and stabilization are conducted as required. International Bird Rescue is deployed to make the wildlife treatment facility operational on Day 2.	W-1 through W-5

TABLE 1-31 (CONTINUED):
RESPONSE STRATEGY
DS-3R PRODUCTION WELL BLOWOUT DURING SUMMER

ADEC REQUIREMENT	RESPONSE STRATEGY	REFERENCES TO THE ACS TECHNICAL MANUAL TACTIC AND THIS ODPCP
(xi) Shoreline Cleanup Plan	Shoreline cleanup operations are initiated once the source of the oil has been stopped, based on a plan approved by Unified Command. A shoreline assessment is conducted to understand the nature and extent of oiling. SCAT teams assess shoreline that receives scattered oiling if oil had escaped TF-3 through TF-5. Based on shoreline assessment, priorities are established for cleanup. Cleanup techniques chosen are based on shoreline type and degree of oiling. *NOTE: The following discussion is based on a speculative prediction of shoreline impact and is presented for illustrative purposes only. Prior to commencement of any shoreline cleanup operation, the affected areas must be surveyed to determine the appropriate response. Specific cleanup techniques to be used will be based on field data obtained at the time of the spill on the shoreline habitats, type, and degree of shoreline contamination and spill-specific physical processes. It is not possible to presuppose the outcome of the SCAT process and/or the decisions of the Unified Command.*	SH-1 through SH-11

1.7 NON-MECHANICAL RESPONSE OPTIONS [18 AAC 75.425(e)(1)(G)]

CPAI will mechanically contain and clean up oil spills to the maximum extent possible. CPAI will request approval for in situ burning from the Federal On-Scene Coordinator (FOSC) and State On-Scene Coordinator (SOSC) when mechanical response methods prove ineffective, or as a tool to minimize environmental damage. See "In Situ Burning Guidelines for Alaska" (ARRT, 2008).

1.7.1 Obtaining Permits and Approvals

Burning is not conducted without approval of state and federal agencies. The CPAI Incident Commander will discuss the option of in situ burning with the FOSC and SOSC. CPAI and ACS will complete an "Application and Burn Plan" (see ACS *Technical Manual* Tactic B-1 and http://dec.alaska.gov/spar/guidance.htm#rplans).

1.7.2 Decision Criteria for Use

In situ burning of spilled oil is considered under conditions such as the following:

- Mechanical recovery is impractical or ineffective.
- Shorelines are threatened.
- Burning would augment the oil elimination capacity of mechanical recovery.
- Present and forecast wind conditions will carry the smoke plume away from populated areas.
- A successful test burn has been conducted.

1.7.3 Implementation Procedures

If the CPAI Incident Commander decides to use in situ burning and obtains the necessary authorization, ACS carries out the response as described in ACS *Technical Manual* Tactics B-1 through B-6 and L-6. When implemented, Tactic B-1 will be conducted consistent with the ARRT's Unified Plan, Annex F, Appendix II, "In Situ Burning Guidelines for Alaska" (ARRT, 2008).

1.7.4 Required Equipment and Personnel

ACS maintains the equipment and personnel for in situ burning as described in ACS *Technical Manual* Tactic L-6 and Tactics B1 through B7.

1.8 FACILITY DIAGRAMS [18 AAC 75.425(e)(1)(H)]

The following vicinity and facility maps are provided in Appendix A for the Kuparuk Field and Pipeline:

Kuparuk Field General Layout ..... Figure A-1
Pipeline Route Vicinity Map ..... Figure A-2
CPF 1 Site Detail..... Figure A-3
DS 1B General Layout ..... Figure A-4
CPF 1 General Layout ..... Figure A-5
CPF 2 Site Detail..... Figure A-6
CPF 2 General Layout ..... Figure A-7
CPF 3 Site Detail..... Figure A-8
CPF 3 General Layout ..... Figure A-9
Pad DS 1A General Layout..... Figure A-10
Pad DS 1C General Layout ..... Figure A-11
Pad DS 1D General Layout ..... Figure A-12
Pad DS 1E General Layout..... Figure A-13
Pad DS 1F General Layout..... Figure A-14
Pad DS 1G General Layout ..... Figure A-15
Pad DS 1H General Layout ..... Figure A-16
Pad DS 1J General Layout ..... Figure A-17
Pad DS 1L General Layout ..... Figure A-18
Pad DS 1Q General Layout ..... Figure A-19
Pad DS 1R General Layout ..... Figure A-20
Pad DS 1Y General Layout..... Figure A-21
Pad DS 2A General Layout..... Figure A-22
Pad DS 2B General Layout..... Figure A-23
Pad DS 2C General Layout ..... Figure A-24
Pad DS 2D General Layout ..... Figure A-25
Pad DS 2E General Layout..... Figure A-26
Pad DS 2F General Layout..... Figure A-27
Pad DS 2G General Layout ..... Figure A-28
Pad DS 2H General Layout ..... Figure A-29
Pad DS 2K General Layout..... Figure A-30
Pad DS 2L General Layout ..... Figure A-31
Pad DS 2M General Layout ..... Figure A-32
Pad DS 2N General Layout ..... Figure A-33
Pad DS 2T General Layout..... Figure A-34
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1.9 RESPONSE SCENARIOS FOR AN EXPLORATION OR PRODUCTION FACILITY [18 AAC 75.425(e)(1)(I)]

Well blowout scenarios include a summary of planned methods, equipment, logistics, and time frames proposed to be employed to control a well blowout within 15 days. CPAI also certifies they currently have and continually maintain a separate blowout contingency that is available to ADEC upon request. Well blowout scenarios are presented in Section 1.6.3.

CPAI has precautions in place that minimize the potential for a loss of well control. Section 2.1.6 outlines the preventive and recovery measures used to minimize spill potential during drilling operations. If an uncontrolled flow occurs at the surface, safety procedures would be employed to protect personnel, stop the spill, protect the environment, and protect the equipment. CPAI well control and emergency response procedures are provided in CPAI's internal *Drilling and Wells Emergency Preparedness and Blowout Contingency Plan*. The Drilling and Wells Management Team is immediately notified upon loss of well control during any drilling or well work operations.

If secondary control is lost, and there is an uncontrolled flow from the wellbore at the surface, detailed plans are made to regain control. A thorough evaluation of the situation is necessary to determine the best course of action, although several courses of action will be initiated to allow for contingencies. CPAI considers mechanical surface control methods such as well capping, the Best Available Technology versus relief well drilling for well source control. However, as required in regulation 18 AAC 75.445(d)(2), CPAI has provisions in place, for drilling a relief well (see "Relief Well" discussion below). Well control planning will be initiated concurrently with various response actions. These response actions include relief well planning, surface control by repair/replacement of blowout preventer (BOP) stack components, and/or installation of additional BOP stack components, dynamic kill design, and downhole plugging. Diversion and/or ignition of flow may also be considered.

Even though preparations for a relief well may be one of the first actions taken, regaining control of the blowout through mechanical means is typically much faster and preferred to drilling a relief well, and generally more successful. In the event of a blowout, every effort is made to regain control of the well through mechanical means by using well control specialists such as Boots & Coots/IWC, Cudd Well Control Company, or Joe Bowden's Wild Well Control, Inc. Specialized personnel and the equipment needed for well control are also available on the North Slope through mutual agreement and can be mobilized within 24 to 48 hours of notification. It is also possible that no mechanical methods will be needed to regain well control. Loss of surface control may cause a pressure drop in the wellbore. As reservoir formations flow, bridging in the wellbore may result, causing the flow to the surface to either be decreased or shut off completely.

1.9.1 Well Capping

Over the past decade, well capping techniques have been developed and proven to be efficient and effective in regaining control of damaged wells and in reducing associated environmental impacts. Significant improvements to well capping techniques and procedures have been developed by a variety of well control specialist companies throughout the world.

Well capping response operations are highly dependent on the severity of the well control situation. CPAI has the ability to mobilize specialized personnel and equipment (capping stack, cutting tools, etc.) to a North Slope location within 24 to 48 hours of notification. The materials required to execute typical mechanical control responses (junk shots, hot tapping, freezing, or crimping) are small enough so they can be quickly made available to remote locations, even by helicopter, if necessary. Other equipment necessary during well capping operations are commonly available on the North Slope (e.g., bulldozers, cranes, pumps, block and tackle, large diameter casing, etc.) and can be made available within a few

hours of the actual emergency. For offshore or remote locations, heavy lift helicopters would be mobilized within 48 hours.

CPAI maintains an operating agreement with Wild Well Control, Inc., a well control specialist organization that can assist in the intervention and resolution of any well control emergency. Wild Well Control acts as CPAI's third party well control specialist. CPAI has access to several international service providers that includes but is not limited to Halliburton, Anadrill Schlumberger, Baker Hughes INTEQ, Dowell Schlumberger, Baroid, and MI Drilling Fluids. CPAI would access the best fit-for-purpose technology to respond to an emergency event. Available services include, but are not limited to, firefighting equipment and services, specialty blowout control equipment and services, directional drilling services, high-pressure pumping services, and experience with specialty fluids, chemicals, and additives. The 24-hour phone number for Wild Well Control is as follows: 1-281-784-4700.

In the event of an actual blowout, well capping operations would commence with CPAI activation of Wild Well Control and mobilization of key personnel and equipment. Attempts at dynamic and surface well control methods will continue if safe conditions exist. If the well capping option is selected, safe reentry to the wellhead area must be established and rig equipment must be moved. If the rig moving system is unavailable or inactive, then heavy bulldozers, block and tackle, and/or cranes will be used to remove the rig from the wellhead area. Once safe access is regained, capping operations can commence.

CPAI and partners maintain, and have available on the North Slope, most of the major equipment that would be required to initiate well capping or other surface control options. Specialized equipment required for well capping is summarized in Table 1-32. Equipment not located on the North Slope can be mobilized in 24 hours.

Well control events where well capping would not be the preferred response involve events in which the potential to release liquid hydrocarbons to the surface is highly unlikely (i.e., shallow gas, compromised surface casing or surface casing cement jobs, broaching or reasonable concern of broaching, inaccessible wellhead and/or casing).

1.9.2 Relief Well

Throughout the world, the number of well control incidents that escalate into the requirement of drilling a relief well is extremely small. CPAI does not rely on relief well drilling as the primary method of source control. However, due to long lead times associated with drilling a relief well, the relief well plan is initiated concurrent with the implementation of surface control methods.

If surface control measures fail, CPAI relief well plans are implemented. A CPAI relief well plan is developed and implemented using industry-recommended practices and approved standards. CPAI decisions are made by drilling management in accordance with procedures contained in the relief well plan.

Identification of surface location, equipment, and timing is dependent on the specific well site conditions. A number of options may be available for location and equipment. Timing is dependent on the success of surface control techniques and well conditions, including any natural bridging, which may occur.

TABLE 1-32:
WELL CAPPING EQUIPMENT LIST

COMPONENT	WELL CAPPING USAGE	LOCATION	AVAILABILITY
6,000 gpm Fire Pumps	Fire and heat suppression	North Slope	<8 hours
Athey Wagons	Tractorized booms for manipulation of tools in and around blowout well	North Slope	<8 hours
D8 Bulldozers	Power for Athey wagons and backup for heavy equipment, rig moving; can also be used for constructing berms to aid in spill containment	North Slope	<8 hours
Backhoes	Drainage ditch, berm construction	North Slope	<8 hours
100-200 ton Cranes	Heavy equipment lifting capability; if well blowout is ignited, may be needed to facilitate rig move	North Slope	<8 hours
50-75 ton Cranes	Smaller, mobile units for spotting support equipment	North Slope	<8 hours
500 ton Drilling Blocks	Block and tackle system for moving or dragging heavy equipment	North Slope	<8 hours
Drilling Line	Component of block and tackle system if rig moving system is inoperable	North Slope	<8 hours
20-inch and 30-inch Casing	Used to construct Venturi tubes to divert blowing well bore fluids (ignited and un-ignited)	North Slope	<8 hours
Misc Equipment	High pressure chicksan, flexible hoses, valves, containment boom, absorbent, hand tools	North Slope	<8 hours
Kill Pumps	Back up to rig pumps	North Slope	<8 hours
Junk Shot Manifold	Manifold system constructed to pump small leak sealing materials into well	North Slope	<8 hours
Hot Tap Tool	Manifold used to gain safe access to pressurized tubulars at surface	North Slope	<8 hours
Crimping Tool	Sized device used to pinch tubulars closed to seal off internal flow	Houston, Texas	<24 hours
Abrasive Cutter	High-pressure cutting tool used to sever leaking BOPs, rig structures	Duncan, Oklahoma	<24 hours
Capping Stack	Various high pressure BOP stacks (to replace leaking, damaged or severed primary BOPs)	Houston, Texas	<24 hours

Relief Well Surface Locations

The optimum surface location for a relief well depends on several factors, including the depth and direction of the wellbore, personnel safety, and weather conditions. The surface location is selected so the relief well can be drilled in the most efficient manner practicable. Other surface location considerations include hole angle, minimization of drilling time, and directional control. Weather conditions may dictate the use of an ice road, ice pad, or gravel pad for relief well surface locations. A number of locations may be suitable for placement of a relief well, e.g., on a pad or road. In addition, a new pad could be built for relief well drilling. The Kuparuk Field infrastructure provides numerous relief well surface locations.

Although extensive precautions are taken, some potential exists for a loss of well control, conceivably requiring the use of a relief well. Plans have been established for initiating such emergency drilling quickly and safely.

Relief Well Drilling Rig and Equipment

All the equipment necessary for drilling the relief well is in drilling stock, either on the North Slope or in Fairbanks. Hercable rigs and truckable rigs can be mobilized, in addition to North Slope modular-wheeled rigs.

CPAI can locate, contract for, and handle all the transporting issues involved with relief rig mobilization, simultaneously with the construction of the alternative drill site. In addition, ACS maintains master service agreements with various contractors, such as aviation services, whose assistance may be required during a spill response.

A relief well is generally considered a last resort in managing a blowout. It is more common for a blowout to be controlled with surface-kill techniques, or for the flow to stop as a result of natural bridging mechanisms or formation depletion, as previously discussed.

In the event of a blowout, every effort is made to regain control of the well through mechanical means by using well control specialists from the North Slope industry through Mutual Aid, and from Wild Well Control. Relief well rig mobilization plans are developed concurrently with surface control actions. The primary relief well option is mobilization of another rig that is in use nearby. This can be accomplished by immediately suspending drilling operations on a nearby rig and moving the rig to the relief well site.

In accordance with standard oil industry practice and through Mutual Aid agreements, other operators would commit the necessary rigs and resources to combat a well control incident if a CPAI-operated rig is unavailable. Operator cooperation and sharing of resources often have been used on the North Slope when rigs, equipment, and other services are in short supply. Although some equipment is specified in the plan, this equipment may be replaced by functionally similar equipment, as necessary.

Relief Well Timing

Preparation for a relief well would begin as early as possible. Rapid mobilization is anticipated for most sites, assuming North Slope rigs are readily available. Use of a local rig could conceivably allow well control to be regained within the following estimated time frame. The time needed to complete the well may increase. The time required for controlling a blowout by drilling a relief well varies, due to a number of unpredictable conditions, such as weather, cause of blowout, choice of surface location, and depth of well. Isolated flooding occurring during spring break-up may increase the time needed to successfully complete a relief well. The amount of time required to execute a relief well is also dependent on the success of surface control techniques and well conditions, including any natural bridging that may occur. Preparation for a relief well will begin as early as possible.

Earthwork equipment is located on the North Slope to immediately begin building a relief well site if necessary. Under winter conditions, an ice pad and necessary roads would be constructed. If conditions require gravel construction, gravel would be hauled from existing gravel mine sites. The rig and supporting relief well equipment would be mobilized during pad construction. When the site location is completed, the equipment would be staged for delivery. Movement of a rig and associated equipment would be accomplished via gravel or ice roads, supported by helicopter transport. The drilling of the well would begin as soon as the rig-up was complete.

Blowout Well Ignition

Ignition of a blowout will be a decision made by CPAI management in conjunction with regulatory agencies. The decision to ignite a blowout will be made only after assessing the probability of implementing successful surface control, reviewing potential safety hazards, addressing pertinent environmental considerations, and obtaining necessary agency approvals. One potential justification for the ignition of a blowout would be a gas blowout where the hydrocarbon had a toxic component (e.g., hydrogen sulfide [H_2S]). In such instances, the blowout may be ignited to control the toxic gases while preparations are made to kill the well. Once well-kill preparations were in place, the fire would be put out and the kill operations would commence. Direct telephone and/or radio communication would be maintained with the Source Control Unit Leader through the IMT should any burning activities occur.

Permits

In the event of a well blowout, a series of federal, state, and local permits are required for response effort support. Permits are needed to authorize construction of gravel pads and/or support facilities (e.g., ice or gravel staging pads, temporary storage areas, temporary water uses).

Federal approval is required (Section 404/10 permit, U.S. Army Corps of Engineers) for placement of gravel (fill) in waters of the United States (wetlands). The Corps has issued Nationwide Permit #20, which authorizes placement of fill needed for cleanup of spilled oil. A request for this authorization requires approval from the Alaska Regional Response Team. This request is typically approved quite rapidly, assuming the Alaska Regional Response Team is in agreement with the overall cleanup strategy for the specific spill event.

In addition to the federal permit, it is likely that State of Alaska and NSB permits also will be required. As part of overall North Slope oil spill preparedness, ACS holds a series of permits authorizing a variety of cleanup-related activities, including excavation and placement of fill. ACS and CPAI review these permits periodically to ensure their applicability, accuracy, and current status.

ACS maintains pre-approved emergency use permits, which may be applied to relief well drilling operations and other spill response activities.

PART 2 PREVENTION PLAN
[18 AAC 75.425(e)(2)]

2.1 PREVENTION, INSPECTION, AND MAINTENANCE PROGRAMS [18 AAC 75.425(e)(2)(A)]

CPAI considers prevention the core of its spill response planning at Kuparuk. Pollution prevention begins with the drilling of wells and extends through all phases of oil production. The following spill prevention methods are used: design; inspection; testing; training; repair, replacement, and preventative maintenance (PM); detection and shutdown procedures; and administrative programs.

2.1.1 Oil Discharge Prevention Training and Recordkeeping [18 AAC 75.020]

CPAI personnel with job duties directly involving inspection, maintenance, or operation of oil storage and transfer equipment regulated under 18 AAC 75.005 through 18 AAC 75.080 are required to complete training on CPAI's Oil Discharge Prevention and Contingency Plan and Spill Prevention, Control, and Countermeasures for CPAI North Slope Exploration and Production Training Module (REQ-229). This module contains information on state and federal oil pollution prevention requirements that are applicable to facility and field operations. A listing of each position required to take this training is maintained by the CPAI Health, Safety, and Environment (HSE) Training Coordinator and documented in the CPAI *Training Requirements Manual*. CPAI personnel and contractors who perform inspections and maintenance are required to maintain the necessary certifications consistent with the applicable industry standard (i.e. American Petroleum Institute [API], National Association of Corrosion Engineers [NACE], and American Society of Mechanical Engineers [ASME]).

A listing of training objectives and the means of achieving them, including training subject, training schedules, frequency, and type, are provided in the CPAI *Training Requirements Manual*. Completion of training is verified by computerized records maintained by the HSE Training Coordinator. Records are prepared and maintained in the HSE training files in a retrievable form for a minimum of five years and shall be provided to ADEC upon request. A summary of key positions and prevention training from CPAI's *Training Requirements Manual* are summarized in Table 2-1.

CPAI requires its contractors to comply with all applicable local, state, and federal regulations. Contractors maintain their own training programs and records. CPAI periodically audits contractor training programs and records as part of the CPAI HSE Contractor Audit Program.

2.1.2 Substance Abuse Programs [18 AAC 75.007(e)]

The CPAI drug policy was established to provide for the safety of employees and contractors, and to establish a safe working environment at all operations. CPAI's company-wide policy is outlined in this section and applies to all employees and contractors:

> "The use, possession or being under the influence of intoxicants, marijuana, or other controlled or illegal substances is STRICTLY PROHIBITED on CPAI-controlled premises. Entry onto CPAI-controlled premises constitutes CONSENT to and recognition of the right of the company to CONDUCT SEARCHES of persons, property, vehicles and living quarters. Violation of this policy or failure to cooperate with a search request will result in TERMINATION for CPAI personnel, and REMOVAL from Company premises for all others."

TABLE 2-1:
SUMMARY OF KEY POSITION AND TRAINING

COURSE CODE	FREQ	TRAINING REQUIREMENT	KUPARUK PROCESSING FACILITIES/DRILL SITES							PIPELINE OPERATIONS			DRILLING/ WELLS		
			Operator Slope Oper	Operator (Lead) Slope Oper / Work Leader	Instrument Tech Slope Inst	Electrician Slope Elect	Mechanic Slope Mech	Facility Engineer Fac Engr	Facility Supervisor Slope Supr	Supervisor Pipeline Supv	Pipeline Coordinator Pipeline KRU	Flow Measurement Specialist Flow Meas	Slope Wells	Slope Drill	Drlg Mgmt
REQ-042-MIX	Initial	Alaska Safety Handbook	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
REQ-014-MIX	Initial	Personal Protective Equipment	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
POL-001-MIX	Tri-Annual	CPAI HSE Policy Overview	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
REQ-055-MIX	Initial	Cultural Awareness	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
REQ-007-MIX	Annual	DOT Pipeline Operation	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓			
REQ-010-MIX	Annual	Emergency Action Plan (Camp)	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
REQ-101-MIX	Initial	Emergency Action Plan – Drilling and Wells											✓	✓	✓
ENV-029-MIX	Initial	Environmental Awareness	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
REQ-001N-KRU	Annual	NPDES - Kuparuk	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	
REQ-022-MIX	Tri-Annual	Hazard Communications	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
REQ-039A-MIX	Annual	Fire Extinguisher (Classroom)	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
REQ-039-MIX	Annual	Fire Extinguishers (Hands-on; Simulator)	✓	✓	✓	✓	✓		✓	✓	✓	✓			
REQ-024-MIX	Annual	HAZWOPER First Responder Awareness						✓							✓
REQ-025-MIX	Annual	HAZWOPER First Responder Operations	✓	✓	✓	✓	✓		✓	✓	✓	✓	✓	✓	
REQ-028-MIX	Annual	HAZWOPER On-Scene Incident Commander		✓					✓	✓	✓		✓	✓	
REQ-229-2007	Annual	ODPCP/SPCC CPAI NS Expl. and Production	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
K-REQ-082-MIX	Tri-Annual	PSM – Kuparuk Facility Overview	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓			
REQ-043-MIX	Annual	PSM – Emergency Action Plan – Kuparuk	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓			
REQ-057-MIX	Initial	Predator and Waste Management	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
REQ-052-MIX	Bi-Annual	Waste Determination and Manifest Trng.		✓							✓		✓	✓	
WEL-087-MIX	Bi-Annual	Well Control (Drilling & Completion)												✓	
WEL-084-MIX	Bi-Annual	Well Control (Well Servicing)											✓		

In addition, CPAI's operation of the Kuparuk Crude Oil Transmission Pipeline (Kuparuk Pipeline) is under jurisdiction of the U.S. Department of Transportation (DOT). These regulations require drug testing for pre-employment; random, post-accident, reasonable cause; and return-to-duty situations for employees in DOT-covered positions. Approximately 33 percent of CPAI employees working as DOT-regulated employees, or in safety-sensitive positions, are randomly screened on an annual basis.

2.1.3 Medical Monitoring [18 AAC 75.007(e)]

Personnel subject to physical fitness requirements must meet minimum physical requirements for their job classification. Compliance with these requirements is checked through physical examinations and/or records.

Because the use of a respirator is required for many jobs, a key aspect of the physical examination is a determination of the employee's physical capability to wear a respirator. A respiratory questionnaire is required in the interval between physical examinations. The primary purpose of the questionnaire is to evaluate whether there have been any changes in the status of the employee's health that may affect his/her ability to wear a respirator. An annual quantitative fit test is also required, as is training in the proper use, storage, and maintenance of the respirator.

Personnel who have not been medically qualified, fit-tested, and trained will not be permitted to use respiratory protective equipment.

All members of CPAI's Hazardous Materials (HAZMAT) Team and the Fire Department are given a physical examination that complies with National Fire Protection Association standards. SRT members require a physical examination every two years.

A medical evaluation may be required if personnel are exposed to, or may be exposed to, hazardous substances at or above the permissible exposure level (PEL). If a PEL does not exist, published exposure levels may be used instead. The exposure will be the ambient air concentration (regardless of respirator use). Medical surveillance also will be provided at the employee's request.

In an emergency, injured personnel will proceed to the Medical Clinic for evaluation and/or treatment after completing decontamination. If there is a medical emergency, the decontamination should be completed within the shortest time possible (no shower unless there has been skin contact; continue to flush eyes while in transit, if necessary), and immediately transport personnel to the Medical Clinic for prompt attention.

If overexposure is known or suspected as a result of an accidental release, the employee(s) is examined and treated as necessary. Medical attention can be rendered by the physician assistants who work under the direction of a physician. Persons requiring additional medical attention are taken to Anchorage by air ambulance or by commercial or company charter for treatment.

2.1.4 Security and Surveillance Programs [18 AAC 75.007(f)]

Fuel Transfer Procedures [18 AAC 75.025]

Fuel transfer procedures for production and exploration facilities are located in Section 3.1.2.

2.1.5 Operating Requirements for Exploration and Production Facilities [18 AAC 75.045]

Flow Tests

Oil produced during a formation flow test or other drilling operations must be collected and stored in a manner that prevents the oil from entering state land or waters. If flow tests are conducted at Kuparuk, oil produced from these tests will be stored in mobile tanks, constructed containment areas, or the well cleanout tank.

Platform Integrity Inspections and Isolation Valves for Pipelines Leaving Platforms

These requirements do not apply to Kuparuk, because Kuparuk is an onshore facility rather than an offshore platform.

Drip Pans and Curbing

Drip pans and curbing are provided at transfer locations.

Catch Tanks

Requirements for catch tanks do not apply to Kuparuk, because Kuparuk is an onshore facility rather than a platform.

Well Cellars

Since mid-2001, well cellars at Kuparuk have been constructed of a 6-foot-diameter, 3/8-inch-thick, steel pipe with a 3/8-inch-thick metal bottom that is seal-welded to the bottom of the cellar. The cellar with the metal bottom has a hole in the center that is the size of the outside diameter of the conductor. The cellar is slipped over the conductor until the bottom of the cellar is approximately 58 inches below the pad elevation. This leaves the top of the cellar approximately 2 inches above the grade of the pad. The bottom of the cellar is then seal-welded to the conductor to form a water-tight container.

Prior to moving the rig over the conductor, a layer of Herculite impermeable liner is placed around the cellar with the edges lapped over the edge of the cellar. Fluids that escape containment on the rig are contained by the Herculite liner of the cellar.

Between 1994 and 2001, well cellars at Kuparuk were constructed using a 5-foot-diameter corrugated metal pipe installed to a depth of 6 feet below the surface grade of the drill site pad. A hole was drilled in the center of the cellar to a depth of 80 to 120 feet and a 16-inch-diameter conductor pipe was run into the hole. The annulus was cemented from the bottom of the hole up into the cellar until the top of the cement was approximately 4 feet below the surface of the drill site. The result was a 2-foot-thick cement seal at the bottom of the cellar between the cellar and the conductor pipe.

Prior to 1994, cement was not placed in the bottom of the cellar and complete vertical containment was not always achieved. In addition, prior to 1994, the predominant conductor pipe diameter was 20 inches.

A description of the well house inspection program is included in Section 2.5.1. Additional inspection programs pertaining to well cellars include:

- An inspection of a well and the surrounding pad is conducted before and after well work is performed on that well. Contamination and general housekeeping cleanup efforts are identified, documented, and addressed after the well work is completed.
- Well houses and well cellars are visually inspected each summer to identify areas of gravel subsidence requiring additional gravel infill.
- A drill site stormwater management plan has been developed to ensure potential contamination from well cellars does not spread to other parts of the drill site. The management plan details procedures to be followed to determine where to discharge the stormwater and how to prioritize the drill site pads for stormwater removal.

Wells drilled and completed after December 30, 2008 will be equipped with sumps designed and installed to be sufficiently impermeable as required by 18 AAC 75.045(d)(2).

Other Requirements for Tanks

Aboveground, onshore oil storage tanks must meet the requirements of 18 AAC 75.065, 18 AAC 75.066, and 18 AAC 75.075. See Sections 2.1.8 and 2.1.9.

Other Requirements for Piping

Onshore piping must meet the requirements of 18 AAC 75.047 and 18 AAC 75.080. See Section 2.1.6.

Blowout Prevention and Emergency Shutdown

Drilling Assurance

This section outlines preventative measures to minimize hydrocarbon spill potential, which are applied to exploration drilling operations and are applicable to onshore facilities. All well control discussions presented in this section are aimed at the prevention of spills (i.e., blowouts where hydrocarbons spill to the surface) during drilling operations. Measures that can be taken to regain well control in the event of lost control are summarized in the response scenarios located in Section 1.6.3. The potential for spill incidents is noted in Section 2.3.

The following definitions apply to this section:

Barrier – During drilling and well activities, the following barriers will normally exist:

- A barrier consisting of a homogenous mud column in hydrostatic overbalance in relation to the reservoir pore pressure.
- A barrier consisting of a cemented casing, wellhead, pipe ram/annular preventer and drill string with Kelly valve/check valve.

Blowout – Any uncontrolled flow of formation fluids to the surface due to formation pressure exceeding the hydrostatic pressure of the mud or fluid column and failure of the second barrier.

Shallow Gas Blowout – Any uncontrolled flow of gas from gas pockets located above the intended reservoir prior to fitting the blowout preventer (BOP).

Completion – Covers any installation of production tubing, packers, and other equipment, as well as perforation and stimulation in production and injection wells.

Exploration Drilling – Covers all operations related to wildcat and appraisal wells between spudding the well and plugging and abandonment.

Kick – Unplanned introduction of hydrocarbons or fluids (brines, water) into the wellbore from formations.

Workover – Covers all intervention operations other than operations carried out with wireline.

Remedial – Covers only those intervention operations where wireline or coil tubing is used.

Well Control During Planning

The process of well control commences before actual drilling operations with the planning and design of any well. This is more onerous for exploration and appraisal wells due to the lesser amount of offset data available to make design decisions. Seismic data and offset well information provide information for the prediction of over-pressured formations below the surface. Drilling engineers use the predictions for formation pressure to design a drilling mud program with sufficient hydrostatic head to overbalance the formation pressures from surface to well total depth. Other factors influencing the mud weight are shale conditions, fractures, lost circulation zones, under-pressured formations, and stuck pipe prevention. Casing strings are then designed to prevent several of these factors affecting the well control performance at the same time. Casing set at proper depths will allow a kick, if taken, to be safely controlled downhole.

Information that is already known regarding formation pressures within the drilling area will be utilized when drilling new wells. In addition, the Alaska Oil and Gas Conservation Commission (AOGCC) has specifications for drilling, casing, cementing, and blowout prevention in 20 AAC 25.

All planning is done in accordance with AOGCC, and where appropriate, Bureau of Land Management (BLM) regulations. CPAI policies and recommended practices are, at a minimum, equivalent to AOGCC and BLM regulations.

Well Control During Drilling

There are two areas where the potential for loss of well control exists during drilling. The first is during the drilling of the surface hole where the potential for a shallow gas blowout exists. It should be noted that shallow gas blowouts do not contain oil, and no spill of oil occurs at the surface. However, the incident is critical from a safety standpoint. The second is while drilling the below-surface hole where a blowout can occur while drilling into the reservoir or other hydrocarbon-bearing zones, or during completion of the well. In both cases, kick identification and management are the primary tools used to prevent a blowout.

Well Control During Surface Hole Drilling

During surface hole drilling, a shallow gas blowout can occur when a small, high-pressure volume of trapped gas is encountered. This causes a rapid unloading of the wellbore fluids (mud) and gas at surface in a very short time span.

Shallow seismic surveys are carried out over the proposed drilling location to establish the presence of gas accumulations. Offset data are also valuable, but accumulations tend to be localized, so caution is vital at all times in case an incident occurs. Detection during drilling or tripping (i.e., running the drillstring into or out of the hole) will be visible by monitoring the returns to the surface from the drilling fluid system, monitoring the volume of drilling fluid required to fill the wellbore, and monitoring the drilling fluid weight in and out of the well to detect any influx of gas into the wellbore.

No attempt is made to shut in the well to contain the gas, because surface formations typically have insufficient strength to prevent gas broaching to the surface from these shallow depths. Instead, the flow of gas is directed away from the rig floor using a diverter valve and diverter line, which vents the gas at a safe distance from the drill rig to atmosphere. Procedures are developed to keep pumping fluid to the drillstring, wherever possible, in attempt to establish primary well control, though most shallow blowouts deplete rapidly and/or bridge off.

Well Control While Drilling Below the Surface Hole

A management-approved, detailed well plan is taken to the rig, and the well is drilled. During drilling, the mud weight (the primary well-control mechanism) is constantly monitored and adjusted to meet actual wellbore requirements. Too low a mud weight could under-balance the well and result in a kick (a flow of formation liquids, oil, gas, or water into the wellbore). Too high a mud weight might result in lost circulation to a weak formation, which can then lead to an under-balanced condition and possible kick. Generally, there is a fairly broad range of mud weight that will provide the proper well control for the hole conditions encountered.

The weight of the mud in the hole is the primary well-control mechanism. Minimum mud specifications are set by the AOGCC. If a kick occurs, secondary well control methods are employed. Constant monitoring of the fluid level in the wellbore and mud pits allows prompt notice of a kick in the hole. If a kick is noticed, the well is shut in using BOP equipment installed on the wellhead after the surface casing is set (below the permafrost). The BOP equipment will close off and contain liquids and pressures in the annulus and in the drill pipe. Pressure measurements are then taken, and the mud in the surface pits is weighted enough to overbalance the bottomhole formation pressure. A standard well-kick procedure is then implemented to circulate the heavy mud through the well and safely remove the kick liquids from the hole. After this procedure is completed, the well is opened and fluid levels are again monitored. Drilling operations resume when all is normal.

The BOP equipment is composed of redundant mechanisms that close the annular area between the drill pipe and the hole. The BOP stack is typically composed of an annular preventer, two pipe ram preventers, and a blind ram preventer. At least two chokes are provided in the choke manifold. Two pumps are typically available. The casing is designed to contain the maximum expected pressures shut in at the surface. Valves on the rig floor are used to shut in the inside of the drill pipe. Gas-busters and de-gassers are used to remove gas from the mud as it is circulated out of the hole. Approximately 1,000 barrels of surface pit capacity is available for storage and circulation of mud. Mud pumps used for drilling are also used to circulate the kick out of the hole.

BOP drills are performed and timed on the rig several times during drilling to verify the well can be shut in quickly and properly. The company rig supervisor, tool pushers, drillers, and derrick men all have certified BOP training in well control that is renewed every two years. Mud men typically have BOP training, especially on exploration wells.

Backup systems and procedures are available for surface control of a kick if the weighted circulation procedures fail to provide the required control. It might be necessary to bullhead the formation liquids in

the wellbore back into the formation. This is accomplished by pumping down both the annulus and the drill pipe at the same time and forcing the liquids back into the formation. The well is then circulated with kill mud weight, and drilling resumes. It might also be necessary to pump heavy mud and then bleed off some of the annulus pressure. This is done through the choke manifold at a controlled rate such that the formation liquids are controlled. Another technique is the dynamic kill procedure. This entails pumping the kill fluid at a rate high enough to overcome the loss zone, control reservoir pressure, and kill the flow. Other manifestations of these basic techniques may be used depending on the situation.

Well Suspension/Abandonment

Upon completion of drilling operations, the well will be plugged and abandoned, or suspended, in compliance with state and federal regulations, as appropriate. No well may be temporarily abandoned for more than 30 days without prior approval from the BLM (43 CFR 3162.3-4). Well suspension and abandonment procedures must also comply with the AOGCC regulations found at 20 AAC 25. All equipment and supplies will be removed, and the site will be cleaned of any refuse.

Spill Prevention Practices and Training

Drilling safety and spill prevention practices and training follow CPAI drilling policy. All drills, training, and inspections required by federal and state laws are conducted. During these drills, particular attention is paid to the driller and tool pusher understanding the importance of knowing and recording where every barrel of mud went while tripping in and out of the hole. In addition, extremely close attention is paid to volumes and fill-up pit systems to verify accurate performance during each trip. Tool pushers check all geolographs, pit level charts, and tour reports for accuracy before forwarding them to the company representative. Drilling crews are required to have First Responder training. They are responsible to the Drilling Supervisor, who acts as the First Responder Incident Commander for any minor spill; however, drilling crews are not part of the major response team. Drilling Supervisors have, as a minimum, 8-Hour Hazardous Waste Operations and Emergency Response (HAZWOPER) refresher training as outlined by Occupational Safety and Health Administration 29 CFR 1910.120(q)(6)(ii), First Responder Awareness Level. Regulated fuel and hydrocarbon storage tanks are contained in a lined and bermed area, as required by regulation.

2.1.6 Flowline and Facility Piping Requirements [18 AAC 75.047 and 18 AAC 75.080]

Flowlines

Flowlines placed in service after December 30, 2008 will be designed and constructed consistent with the standards identified in 18 AAC 75.047(b). Flowline piping supports will be constructed in accordance with the applicable piping standards. CPAI shall ensure the piping is protected from atmospheric corrosion by the application of a protective coating or by the use of corrosion-resistant material, unless CPAI demonstrates by test, investigation, or experience appropriate to the environment of the piping segment that the anticipated extent of corrosion only will be a light surface oxide, or will not affect the safe operation of the piping before the next scheduled inspection. CPAI ensures that measures for corrosion control on flowlines are consistent with 18 AAC 75.047.

CPAI maintains a corrosion control program and an inspection program on flowlines, consistent with API Standard 570 and Chapter VIII of ASME Standard B3.14-2002, as required in 18 AAC 75.047(c)(1). External inspections for painted or bare flowlines will be conducted every three years per ASME B31.4, and external inspections for insulated flowlines will be conducted every five years per API 570. Several engineering and design piping specifications are guiding resources for the corrosion control program.

A waiver of the requirements to place line markers at 1-mile intervals along each flowline was approved by ADEC. Line markers were installed at each below-grade crossing and where remote flowlines approach drill pads. A copy of the waiver letter is included in Section 2.6.

Flowlines removed from service for more than one year will be free of accumulated oil and isolated from the system as required by 18 AAC 75.047(f). For purposes of this subsection, “removed from service” means not in regular use for the service intended and not included in a regular maintenance and inspection program. CPAI will notify ADEC when flowlines are removed from service and when requirements of this subsection have been completed.

Facility Piping

Facility oil piping placed in service after December 30, 2008 will be constructed to ASME standards B31.3, B31.4, B31.8, or another ADEC-approved equivalent. CPAI shall ensure the piping is protected from atmospheric corrosion by the application of a protective coating or by the use of corrosion-resistant material, unless CPAI demonstrates by test, investigation, or experience appropriate to the environment of the piping segment that the anticipated extent of corrosion will be only a light surface oxide, or will not affect the safe operation of the piping before the next scheduled inspection. Facility piping supports will be constructed in accordance with applicable piping construction standards.

Facility oil piping containing oil is maintained in accordance with a corrosion control program as required by 18 AAC 75.080(b). Facility oil piping and valves are visually inspected for leaks or damage during routine operation, or at least monthly, as required by 18 AAC 75.080(n).

After December 30, 2008, cathodic protection systems installed on facility piping will be consistent with 18 AAC 75.080(f). Cathodic protection systems will be designed and installed under the supervision of a corrosion expert.

Cathodic protection systems on facility piping will be maintained and inspected in accordance with 18 AAC 75.080(k).

Aboveground facility piping is protected from vehicles by bollards, guardrails, limited-access roads, and/or warning signs/reflectors where needed.

CPAI will notify ADEC of any facility piping removed from service for more than one year. Facility piping removed from service for more than one year will be free of accumulated oil, identified as to origin, marked with the words “Out of Service” and the date taken out of service, secured to prevent unauthorized use, and blank-flanged or isolated from the system.

Inspection and Monitoring Program for Flowlines and Facility Piping

Inspection and monitoring of flowlines and facility piping are used to indicate if additional corrosion control is required and provide feedback to the success of the overall corrosion control program.

At a minimum, the intervals between flowline inspections meet the requirements of ASME B31.4-2002 for bare flowlines and API 570 for insulated flowlines. The Kuparuk Pipeline is inspected to the requirements of the State Pipeline Coordinator’s Office.

Many factors determine the interval between successive inspections. Safety, history of the piping and similar-service piping, and state and federal regulations influence the frequency of inspections. Inspection

and monitoring programs for internal and external corrosion use different methods, including the following:

Coupon Monitoring. Metallic coupons are strategically placed at high-potential corrosion areas. The coupons are periodically removed, cleaned, and inspected to check for potentialpipeline corrosion tendencies and to monitor corrosion inhibitor effectiveness. New coupons are then installed.

- **Ultrasonic Inspection (UT).** Ultrasonic techniques use acoustic waves to measure metal thickness and uniformity. Corrosion can be detected by the changes in these parameters. In addition to determining a baseline wall thickness, UT can be used to determine changes in wall thickness with time. Specific locations are inspected and monitored for change with UT quarterly to provide feedback to the corrosion control program.
- **Radiographic Inspection (RT).** Radiographic (x-ray) inspections are performed. The radiographs provide images of metal thickness and uniformity. In addition to providing a measure of the extent and depth of damage, RT can be used to determine changes in damage with time. Specific locations are inspected with RT periodically to monitor change and provide feedback to the corrosion control program.
- **In Line Inspection a.k.a "Smart Pigs."** In line inspection is used to inspect pipelines for internal and external damage. Those lines capable of handling smart pigs are inspected with smart pigs periodically, as determined by risk assessment and DOT regulations.
- **Visual Inspections.** Pipelines are inspected visually per the requirements of API 570. Visual inspections often entail UT measurements along with visual observation of the piping.
- **Forward-Looking Infrared System (FLIR).** Aerial FLIR surveillance is utilized to survey piping for temperature anomalies that could be indicative of a leak or certain other conditions.

Equipment and facilities at Kuparuk are maintained through the use of a computer-based Preventative Maintenance (PM) program. The PM program was implemented to schedule maintenance at appropriate intervals to ensure that equipment is fit for service. The program undergoes continual refinement by incorporating feedback from the field based on inspection results. In general, however, most corrosion inspections are driven by CPAI's corrosion database, which may generate more frequent inspections than those scheduled by the PM program. Corrosion inspection records are kept and maintained in the database in accordance with API 570.

The PM program supports continued operational reliability of any flowline system component affecting quality, safety, and pollution prevention as required by 18 AAC 75.047(d)(2). The PM program is intended to be comprehensive. Inclusion in this ODPCP of all inspections performed in conjunction with PM cycles for vessels, pipelines, containment areas, and tanks is impractical because of the volume of written records. At scheduled intervals, these forms are generated by an automated PM information system located and accessed on site at Kuparuk. At the completion of the PM inspection cycle, the forms are reviewed for completion, and results and data are entered into the database for the particular equipment. This provides a historical base for each component. A review of proposed changes in pipeline operation to evaluate potential impacts on pipeline integrity is included as a task in the CPAI Management of Change procedure.

The Kuparuk Pipeline is operated and maintained according to the pipeline operating and maintenance manual; and the Pipeline is maintained and inspected in accordance with 49 CFR 195.

Corrosion Control Program

Applied corrosion control measures reflect the active or potential corrosion mechanisms in the relevant system. The corrosion mechanisms can be divided into internal mechanisms that vary with the service and external mechanisms that are constant for all services.

CPAI tracks spill events for corrosion-related leaks and spills and conducts one or more of the following: Root Cause Analysis, Physical Cause Analysis, or Latent Cause Analysis as required by the situation. If a spill occurs from piping or a tank due to corrosion, a survey of the area is conducted, including wall thicknesses, to determine the full extent of the affected area. Additionally, historical corrosion survey information for the area is reviewed in order to better understand and analyze the corrosion mechanisms and subsequent causes of the leak. Based on the results of these studies, a decision is made to either replace or repair the equipment. As applicable, other areas in the field operating with similar environments or histories are reviewed and surveyed to prevent similar spills or leaks from occurring. Inspection priorities are adjusted based on the outcome of such an analysis. In areas of concern, such as highly corrosive environments, corrosion inhibitors may be used and surveys may be conducted more frequently to help identify and mitigate future occurrences.

Pipelines in corrosive service may be protected from corrosion by the following techniques when inspection or monitoring data indicate adequate protection does not exist:

- **Cathodic Protection.** Cathodic protection prevents current from leaving the pipe and minimizes corrosion. Galvanic cathodic protection uses anodes that are consumed, while providing electrons to the metal to be protected. Impressed current cathodic protection uses a rectifier and anodes to provide electrons to the metal to be protected. Cathodic protection requires a continuous electrolyte (such as water) between the anode and the metal to be protected.
- **Coating.** Coating with polymeric materials is used to protect the steel from corrosive fluid. These polymeric materials provide a barrier between the metal and fluid.
- **Corrosion Inhibitors.** Chemical corrosion inhibitors are used to continuously coat the inside of pipelines or to inhibit chemical corrosivity of the produced fluids.
- **Biocide.** Biocide is used to prevent growth of bacteria within the oil production and water system.
- **Pigging.** Seawater pipelines, produced water pipelines, some production pipelines, and the 24-inch section of the Kuparuk Pipeline are routinely pigged to remove scale and deposits that can allow corrosion to occur. Pigging can allow corrosion inhibitors to work more effectively by providing a clean surface.
- **Maintenance Procedures for Pipe Casings.** Pipe casings under road crossings are inspected annually for the presence of soil and debris that may be in contact with piping. When encountered, the soil and debris are removed to reduce the potential for external corrosion.

Documentation of corrosion control measures includes dates and locations of inspections and tests, test data evaluations, data and analysis of chemical optimization activities, analysis of corrosion trends, and a list and description of repair activities undertaken as required in 18 AAC 75.047(h)(1).

External Corrosion Control

As of December 30, 2008, external corrosion of aboveground flowlines will be controlled by a corrosion control program that includes an application of a protective coating, the use of corrosion-resistant alloys, or another method approved by ADEC, unless CPAI demonstrates by test, investigation, or experience appropriate to the environment of the flowline segment, that the anticipated extent of corrosion will not affect the fitness for service as required by 18 AAC 75.047(c)(3).

Field weld joints are protected by a weather-resistant insulation kit. In accordance with 18 AAC 75.080(l), the effectiveness of field-joint insulation designs or alternative corrosion mitigation methods is confirmed by inspection of a representative sampling of the weld packs after five years of service. Weld pack designs have been improved. Inspection of insulation systems is an ongoing process, with resources and technology applied using a risk-based methodology. Where corrosion is found, appropriate action is taken, including repairs (such as sleeves, if required), application of tape-wrap coatings, and installation of new insulation and jacketing. This refurbishment technique has performed well, with no corrosion found under any previously refurbished weld pack.

Internal Corrosion Control

Internal corrosion of flowlines are controlled by mitigation and monitoring measures consistent with 18 AAC 75.047(c)(4). Methods may include maintenance pigging, treatment of residual water, and inhibitor injection. Internal corrosion mechanisms include carbon dioxide (CO_2) corrosion, microbial-induced corrosion, and chemical attack.

The potential for CO_2 corrosion is low at Kuparuk because of the low concentration (less than 2 percent) of CO_2 in the gas phase. CO_2 corrosion control is achieved using corrosion inhibitors that are injected at the drill sites. The chemical treatment volumes are based on the water production of the drill site and the corrosivity of the fluids.

Microbial-induced corrosion is present in the production and water injection systems. Microbial-induced corrosion is controlled through use of corrosion inhibitors in the production system and through biocides and pigging in the water injection system.

Chemical attack can occur where corrosive chemicals are injected into a system without a properly designed injection quill, where the concentrated chemical is allowed to contact the pipe wall. Chemical attack is controlled by using properly designed quills, low-corrosivity chemicals (where possible), and by frequent inspection of injection points pursuant to API 570.

Where corrosion is found, appropriate action is taken, including repairs (such as sleeves or line section replacement, if required), increased monitoring of the damage, or increased corrosion inhibitor injection.

Below-Grade Portions of Lines

The Kuparuk program for buried and below-grade (cased) piping was developed in January 1998. The purpose of the plan was to address potential concerns from corrosion in piping that is, or has the potential to be, in direct contact with soil and/or water, such as those located in utilidors and casings (e.g., at road crossings). The program uses inspection methods such as long-range UT techniques and in line inspection to determine the need for corrective action. In addition, the program provides the rationale for inspection schedules and the procedures for taking corrective action. External corrosion control for buried or submerged flowlines is consistent with NACE RP0169-2002.

2.1.7 Leak Detection, Monitoring, and Operating Requirements for Crude Oil Transmission Pipelines [18 AAC 75.055]

The Kuparuk Pipeline is a DOT-regulated pipeline system transporting processed crude oil from the KRU and surrounding areas eastward to the Trans Alaska Pipeline System (TAPS) Pump Station 1. Leak detection for the Kuparuk Pipeline consists of metered volume balancing, computational pipeline monitoring (CPM), and visual surveillance. Additional description of leak detection systems is in Section 2.5.2.

Metered volume balancing is performed at least once every 24 hours, as required by 18 AAC 75.055(a)(2). CPM is the primary means of providing continuous leak detection capability, as required by 18 AAC 75.055(a)(1). The flow of incoming oil can be stopped within one hour after detection of a spill, as required by 18 AAC 75.055(b). In the event of an alarm, the control board operator proceeds through a series of steps to determine its cause. CPAI notifies ADEC in writing within 24 hours if a significant change is made to, or occurs in, the leak detection system as required by 18 AAC 75.475(d)(1).

With the exception of the line segments that pass through the various culverts below road crossings, the Kuparuk Pipeline is supported above ground on vertical support members (VSMs). Much of the line is close to the road.

Visual inspections are carried out by either flying over or driving along the pipelines to ensure minor leaks are found and corrected as soon as possible. Visual aerial surveillance of DOT-regulated pipelines is conducted weekly (safety and weather permitting) in accordance with 18 AAC 75.055(a)(3); and a log is completed by surveillance personnel. Ground-based visual inspections occur several times a week (safety and weather permitting) and a log is completed by Security personnel and filed in the Kuparuk Environmental files. As an added measure of leak detection, aerial surveillance is conducted weekly using the FLIR-equipped Twin Otter, weather and safety conditions permitting. FLIR surveillance schedules may be delayed due to emergency use of the FLIR outside of KRU, or mechanical failure or routine maintenance of the Twin Otter or FLIR. Therefore, CPAI relies on weekly visual aerial surveillance to meet requirements of 18 AAC 75.055(a)(3). Adverse weather conditions may prevent visual inspections and detection of minor leaks at rates below those that can be detected by electronic leak detection methods.

2.1.8 Oil Storage Tanks and Secondary Containment Areas [18 AAC 75.065, 18 AAC 75.066, and 18 AAC 75.075]

Regulated Oil Storage Tanks

Stationary and portable oil storage tanks greater than 10,000 gallons at Kuparuk facilities are regulated by ADEC and fall under the provisions of 18 AAC 75.065 and 18 AAC 75.066. ADEC-regulated stationary oil storage tanks at Kuparuk are listed in Table B-1, regulated portable oil storage tanks owned by CPAI are listed in Table B-2, regulated oil storage tanks rented or leased by CPAI are listed in Table B-3, and regulated oil storage tanks not owned or leased by CPAI are listed in Table B-4. (See Appendix B.) Information about descriptions, inspection, secondary containment, and locations of U.S. Environmental Protection Agency (EPA) SPCC-regulated oil containers are provided in CPAI's Kuparuk Spill Prevention, Control, and Countermeasures (SPCC) Plan available at the facility and via the CPAI intranet. The Kuparuk SPCC Plan includes a list of oil containers with capacity of 55 gallons or more and facility diagrams showing their location.

Shop-fabricated ADEC-regulated oil storage tanks placed into service before December 30, 2008 are not subject to ADEC requirements for construction standards.

Tank Standards and Inspections

ADEC-regulated field-constructed oil storage tanks constructed and installed after December 30, 2008 will be consistent with API 650, API Spec 12D, or another equivalent standard approved by the ADEC and will not be of riveted or bolted construction.

ADEC-regulated shop-fabricated oil storage tanks placed in service after December 30, 2008 will be consistent with 18 AAC 75.066(a)(2).

Facility oil containers may be inspected by one or more of the following methods:

- **Ultrasonic Inspection.** Ultrasonic techniques use sound to measure metal thickness and uniformity. Corrosion can be detected by the changes in ultrasonic measurements.
- **Radiographic Inspection.** Radiographic (x-ray) monitor inspections are performed. The radiographs provide images of metal thickness and uniformity.
- **Visual Inspections.** Internal and external visual inspections are conducted. CPAI conducts exterior tank inspections as described in API 653, Chapter 6, STI-SP001, and/or written procedures.
- **Electro-Magnetic Acoustic Transmission.** Used to inspect elevated tank floor over support beams.

Staff or contract certified tank inspectors inspect CPAI-owned aboveground, field-constructed and shop-fabricated storage tanks in accordance with API 653 and ADEC requirements for regulated tanks (18 AAC 75.065 and 18 AAC 75.066). Maintenance and inspection frequencies are consistent with written procedures and/or API 653 or API Recommended Practice 12R1, and as specified in 18 AAC 75.065(b) for aboveground, field-constructed oil storage tanks and 18 AAC 75.066(f) for aboveground, shop-fabricated oil storage tanks.

CPAI inspects and maintains tanks in accordance with a tank management and integrity program. The program outlines inspection requirements for tanks owned, leased, or operated by CPAI. Tanks not owned, leased, or operated by CPAI (otherwise referred to as third-party tanks) must be inspected and maintained by the tank owner. CPAI pre-qualifies third-party service companies to ensure their practices are in accordance with their respective tank management programs. Tanks provided by non pre-qualified companies are audited by CPAI prior to being placed into service. CPAI's Tank Management and Integrity Program has been provided to ADEC. EPA SPCC-regulated oil containers are inspected in accordance with CPAI preventative maintenance programs, which include periodic visual inspection conducted according to written procedures.

Records of inspection and corrective actions taken are maintained by CPAI for the service life of the tank or in accordance with usual and customary business practices. These records may be provided to the ADEC upon request as required by 18 AAC 75.065(d). Tanks subject to internal and external inspection schedules are maintained in CPAI's Corrosion database. The PM database also documents the means and format of accomplishing the inspections for oil containers.

Notifications and Service Status

CPAI notifies ADEC as soon as practicable before a regulated field-constructed tank undergoes major repair or alteration as defined in API 653. ADEC is also notified when the tank is returned to service following major repairs as required in 18 AAC 75.065(e).

CPAI will notify ADEC when a field-constructed, regulated tank is removed from service for more than one year. The tank will be made free of accumulated oil; marked "Out of Service," with the date taken out of service; secured to prevent unauthorized use; and blank-flanged or disconnected from facility piping as required in 18 AAC 75.065(o).

Corrosion Control Program for Tanks

Tanks in corrosive service are protected from corrosion by one or more of the following:

- **Cathodic Protection.** Cathodic protection prevents development of electrochemical current that leads to corrosion.
- **Coating.** Coating with corrosion-resistant materials is used in many pipelines and vessels to protect the steel from corrosive fluid.
- **Biocide Use.** Biocide is used to prevent growth of corroding bacteria within the oil production system.

Cathodic protection systems for field-constructed aboveground oil storage tanks will be operated and maintained consistent with NACE RP0193-2001. A corrosion expert will oversee cathodic protection survey specified under that standard as required by 18 AAC 75.065(h)(1)(D) or (i)(3).

When a cathodic protection system or another approved corrosion control system for field-constructed, aboveground oil storage tanks is installed after December 30, 2008, it will be installed to protect the bottom of each tank from external corrosion, unless deemed unnecessary by an evaluation conducted by a corrosion expert in accordance with API RP 651. If a cathodic protection system is installed, it will be designed and installed under the supervision of a corrosion expert. Cathodic protection test lead wires are in a condition that enables electrical measurements to determine the effectiveness of a cathodic protection system.

Overfill Protection

Kuparuk operations follow the North Slope Fluid Transfer Guidelines in the *North Slope Environmental Field Handbook*, which describe practices for responsible transfers. Before transfers begin, all tank and container levels are checked to prevent overfilling. Overfill protection and/or discharge prevention devices are tested before each transfer operation, or monthly, whichever is less frequent. If monthly testing would necessitate interrupting the operation of a system subject to continuous flow, monthly inspection and annual testing may be substituted for the monthly testing as required in 18 AAC 75.065(l) and 18 AAC 75.066(h). Absorbents or catch basins are placed under connections and vents to contain potential leaks or drips.

Field-constructed and shop-fabricated oil storage tanks utilize visual inspection of tank level and/or sight glasses, level sensors, and high/low-level alarms that show remotely in the associated facility control room or on the tank itself. The type of tank liquid-level determination used in Kuparuk tanks is a function of the liquid in the tank and the operational history of the level technology used in that tank. These technologies vary from differential pressure indicators and float displacement switches, which have been in use for many years, to radar, which is a newer, more sophisticated technology. The liquid-level

determination technology used on these tanks is continually evaluated for its effectiveness and maintenance requirements and then compared against newer technologies that could provide more accurate and cost-effective service. This continual technology assessment has resulted in the assortment of liquid level indicators used in Kuparuk.

CPAI shall ensure shop-fabricated tanks placed in service after December 30, 2008 are equipped with, at each tank fill connection, a fixed overfill spill containment system designed to prevent a discharge when a transfer hose or pipe is detached from the tank fill pipe as required in 18 AAC 75.066(g)(2).

Visual Inspections

Tanks are visually inspected by operations personnel in performance of routine duties. Minor leaks and leaks from tanks at production facilities without low-level alarms would be detected within 12 hours due to the frequent independent visual observations. Operator surveillance serves as the primary leak detection for hydrocarbon tanks.

Periodic recording of tank levels by operations personnel will detect unaccounted losses if a tank develops a leak. Tank surveillance schedules and procedures are contained in Kuparuk's PM system.

2.1.9 Secondary Containment Areas for Oil Storage Tanks [18 AAC 75.075]

Secondary containment is provided at all permanent tank installations. Secondary containment areas are constructed and maintained according to ADEC requirements of 18 AAC 75.075 and applicable ADEC waivers in place (Section 2.6). Secondary containment areas meet EPA requirements of 40 CFR 112.7(c), and 112.8(c) or 112.9(c), as applicable to facility type; areas with ADEC waivers meet EPA impracticability requirements. (See Kuparuk SPCC Plan impracticability determination.) CPAI-owned tank secondary containment inspections are conducted in accordance with company procedures and 18 AAC 75.075(c).

Shop-fabricated portable aboveground oil storage tanks of a vaulted, self-diked, or double-walled design are not required to be placed within bermed, lined, secondary containment areas if they are equipped with catchments that positively hold overflow due to tank overfill or divert any overflow into an integral secondary containment area as required by 18 AAC 75.075(h).

Diked areas for tankage containing fuel or other hydrocarbons, including crude oil, are lined with a synthetic liner and sized to approximately 110 percent capacity of the largest single tank. The containment capacity is sized for the entire volume of the largest tank, plus an allowance for precipitation. In addition, CPAI has a Standard Operating Procedure (SOP), which describes the dimensions of the containment based on size and number of tanks when constructing secondary containments for portable tanks. Liners are resistant to operational damage and weather, and are sufficiently impermeable as required by 18 AAC 75.075(a)(2).

Diked areas are drained as required to recover containment capacity each year due to snowmelt. Rainwater and snowmelt are removed under the provisions of CPAI's National Pollutant Discharge Elimination System (NPDES) General Permit for Stormwater Discharges Associated with Industrial Activity.

Some hydrocarbon processing modules have inside diked storage areas that consist of a liquid-tight perimeter steel dike that would confine spills to individual modules. A floor sump in some modules provides additional containment. Liquids are manually transferred from the module sumps or automatically routed back through the oil production system. Site-specific information is detailed below.

CPF-1

Central Production Facility (CPF) CPF-1 was designed with a secondary containment system that includes dikes, liners, and sloping. Lined dikes or vertical steel walls provide secondary containment for the produced water tanks, the bulk chemical storage tanks, slop oil tank, and the diesel storage tanks. Each secondary containment area has a volume sized up to 100 percent of its largest tank, plus additional volume for precipitation, unless this requirement is waived by ADEC.

Personnel on duty 24 hours a day would detect a significant spill and initiate responses and additional containment procedures. Small to moderate leaks from failures of tanks or vessels containing bulk chemical substances, crude, glycol, lube oil, or methanol, located within the facility, would be controlled by a floor drain sump system and the modular "cell" design of the facility itself.

CPF-2

Lined dikes or vertical steel walls provide secondary containment for the produced water tanks, bulk chemical storage tanks, slop oil tank, crude storage tanks, and diesel storage tanks. Each secondary containment area is sized up to 100 percent of the largest tank it contains, plus additional volume for precipitation, unless this requirement is waived by ADEC.

Personnel are on duty 24 hours a day and would initiate spill response and containment measures. As discussed for CPF-1, small to moderate leaks within the facility would be controlled by a floor drain sump system and the modular “cell” design of the facility itself.

Drill Sites

The drill site manifold module containing the test separator vessel, depending on the volume, may contain a spill in the event of rupture or failure. The production heater vessel containing glycol would discharge to the relatively level gravel pad. Routine tours of drill site facilities by Operations personnel would detect a leak or spill from the crude oil heaters. In the event of a flowline rupture or failure, subsurface, and/or surface valves from the well would be closed by a low-pressure sensor to prevent continued discharge. Check valves located in the manifold module will prevent backflow from other flowlines in production. Low-pressure alarms would summon Operations personnel for spill response and containment.

Secondary Containment Inspections

Secondary containment areas for regulated tanks are routinely maintained free of debris, vegetation, excessive accumulated water, or other materials or conditions that might interfere with the effectiveness of the system. Facility personnel visually check for the presence of oil leaks or spills within secondary containment areas during routine operations and, unless precluded by safety concerns or weather conditions, conduct documented weekly inspections of secondary containment areas for ADEC-regulated tanks, including checking for debris and vegetation, proper alignment and operation of drain valves, visible signs of oil leaks or spills, and defects or failures of the secondary containment system as required by 18 AAC 75.075(c).

Outside containment areas are inspected at the onset of warm weather. Impounded fluids are checked for potential contaminants. If visible contamination is present, vacuum trucks recover and transfer the fluids for recycling or disposal. During these inspections, the secondary containment is inspected, as are the tanks, piping, and associated valves/fittings. To provide maximum containment volume throughout the summer, rainwater and snowmelt are removed under the provisions of National Pollutant Discharge Elimination System (NPDES) General Permit No. AK-R-00-A672 for Stormwater Discharges Associated with Industrial Activity. CPAI keeps a written record of each NPDES-permitted drainage operation for five years, whether or not a sheen is present.

Loading/Unloading Areas

Liquids unloaded to production and drill site facilities go into modules that in some instances have a liquid-tight perimeter steel dike. Some of these facilities have floor sumps. A containment system is also located at the Bulk Sales Fuel Loading Dock, Oily Waste Injection Facility, and the CPF-1 Recycle Facility. The systems' design allows the tanker vehicle to pull onto the lined sump area. Wheel chocks or warning signs are used to prevent premature movement of the vehicle during loading. If spills occur in these areas, the liquid is removed by a vacuum truck and recycled or disposed of as appropriate. Other field fluid-handling areas are protected by secondary containment provided by gravel pads sloped to a remote catch basin. In addition, operational-sized portable containment is placed under line connections and fill points. Warning signs remind drivers to disconnect before departure. Loading/unloading areas are visually inspected once a month or before each transfer, whichever is less frequent. Kuparuk's loading and unloading areas are summarized in Table 2-2.

Unloading areas associated with lube oil tanks at CPF-1, CPF-2, and CPF-3, (tanks T-177, T-AN177, and T-EF62, respectively) and the slop oil tank (tank T-EF01) and diesel storage tank (tank T-EF03) at CPF-3 are considered seasonal or short-term use areas and requirements of 18 AAC 75.075(g) do not apply (see June 22, 2011 and December 14, 2011 "Waiver not required" letters, Section 2.6).

TABLE 2-2:
KUPARUK OPERATING AREA TANK TRUCK LOADING/UNLOADING AREAS

FACILITY	LOADING AREA	SERVICE	MAXIMUM BULK TRUCK COMPARTMENT SIZE (bbl)	BULK TRUCK AREA LINED? (Y/N)	LINER TYPE	SIZE / CAPACITY OF LINED AREA FOR BULK	BERMS, TRENCHES OR DRAINS FOR LOADING AREA CONTAINMENT	PHYSICAL BARRIERS, LIGHTS, OR SIGNS	WAIVERS IN EFFECT
CPF-1	Truck Loading Bays A & B	Diesel fuel storage tanks (Tanks 19-501, 19-502, 19-503, 19-504)		Y	Steel containment pan with 8228 oil resistant low temperature (ORLTA) liner underneath		Drain sumps	Lights and signs	None
CPF-1	Truck Loading Bays C & D	Diesel fuel storage tanks (Tanks 19-501, 19-502, 19-503, 19-504)		Y	Concrete slab with high density polyethylene (HDPE) liner		Drain sumps	Lights and signs	None
CPF-1	Oily Waste Recycling Unloading Area	Oily waste & contaminated water (Tanks T-1002A, T-1002B, T-1005, T1009)		Y	Concrete slab with HDPE liner		Slight grade towards center sump	Drive into and exit loading area in same direction	None
CPF-2	Diesel Fuel Loading Area	Diesel fuel storage tank (Tank T-4201)		Y	Concrete slab with HDPE liner		Slight grade towards center sump	Lights and signs	None
KIC	Tank Farm Loading Area	Slop oil, diesel, and diesel gel (Tanks PGE-86AT, PGE-86AW, PGE-86AZ, PGE-86BE, PGE-86CE, PGE-86CF)		Y	Concrete slab with HDPE liner		Below-grade sump	Signs	None
KIC	Old Fueling Station (out of service)	Diesel fuel & gasoline storage tank (out of service)		N			Slight grade towards center sump	None	None
KRU Landing Area	Aviation Fuel Loading Area	Fuel storage tank (Tank V-702)		N				Bollards and rails	April 8, 2014 Section 2.6
1R-18 Injection Facility	DS-1R Class 2 well Injection Facility unloading area	RCRA exempt drilling fluids, diesel (Tanks PGE-86AV, PGE-86BG, PGE-86AR)		Y	HDPE liner between plywood boards covered by rig mats		Below-grade (drive-through) sump	Flagging	None
DS-1B Injection Facility	DS-1B Injection well facility unloading area	RCRA exempt drilling fluids, diesel (Tanks MI SWACO: T-20451, T-20452, T-0001 to 0005)		Y	HDPE liner between plywood boards covered by rig mats		Below-grade (drive-through) sump	Flagging	None

TABLE 2-2 (CONTINUED)
KUPARUK OPERATING AREA TANK TRUCK LOADING/UNLOADING AREAS

Facility	Loading Area	Service	Maximum Bulk Truck Compartment Size (BBL)	Bulk Truck Area Lined? (y/n)	Liner Type	Size / Capacity of Lined Area for Bulk Trucks	Berms, Trenches or Drains for Loading Area Containment	Physical Barriers, Lights, or Signs	Waivers in Effect
DS-2B *Planned 2014*	Diesel Fuel Loading Area	Diesel fuel storage tank (Tank T-2B01)		Y	Concrete slab with HDPE liner		Slight grade towards center sump	Lights and signs	None
DS-2C *Planned 2014*	Diesel Fuel Loading Area	Diesel fuel storage tank (Tank T-2C01)		Y	Concrete slab with HDPE liner		Slight grade towards center sump	Lights and signs	None
DS-2X *Planned 2014*	Diesel Fuel Loading Area	Diesel fuel storage tank (Tank T-2X01)		Y	Concrete slab with HDPE liner		Slight grade towards center sump	Lights and signs	None
DS-2Z *Planned 2014*	Diesel Fuel Loading Area	Diesel fuel storage tank (Tank T-2Z01)		Y	Concrete slab with HDPE liner		Slight grade towards center sump	Lights and signs	None
DS-2H *Planned 2015*	Diesel Fuel Loading Area	Diesel fuel storage tank (Tank T-2H01)		Y	Concrete slab with HDPE liner		Slight grade towards center sump	Lights and signs	None
DS-2D *Planned 2015*	Diesel Fuel Loading Area	Diesel fuel storage tank (Tank T-2D01)		Y	Concrete slab with HDPE liner		Slight grade towards center sump	Lights and signs	None
DS-2U *Planned 2015*	Diesel Fuel Loading Area	Diesel fuel storage tank (Tank T-2U01)		Y	Concrete slab with HDPE liner		Slight grade towards center sump	Lights and signs	None

2.2 DISCHARGE HISTORY [18 AAC 75.425(e)(2)(B)]

The history of known discharges of volumes greater than 55 gallons is maintained in the CPAI Spill database for the life of the facility. The database includes the source, cause, amount of the discharge, and corrective actions taken.

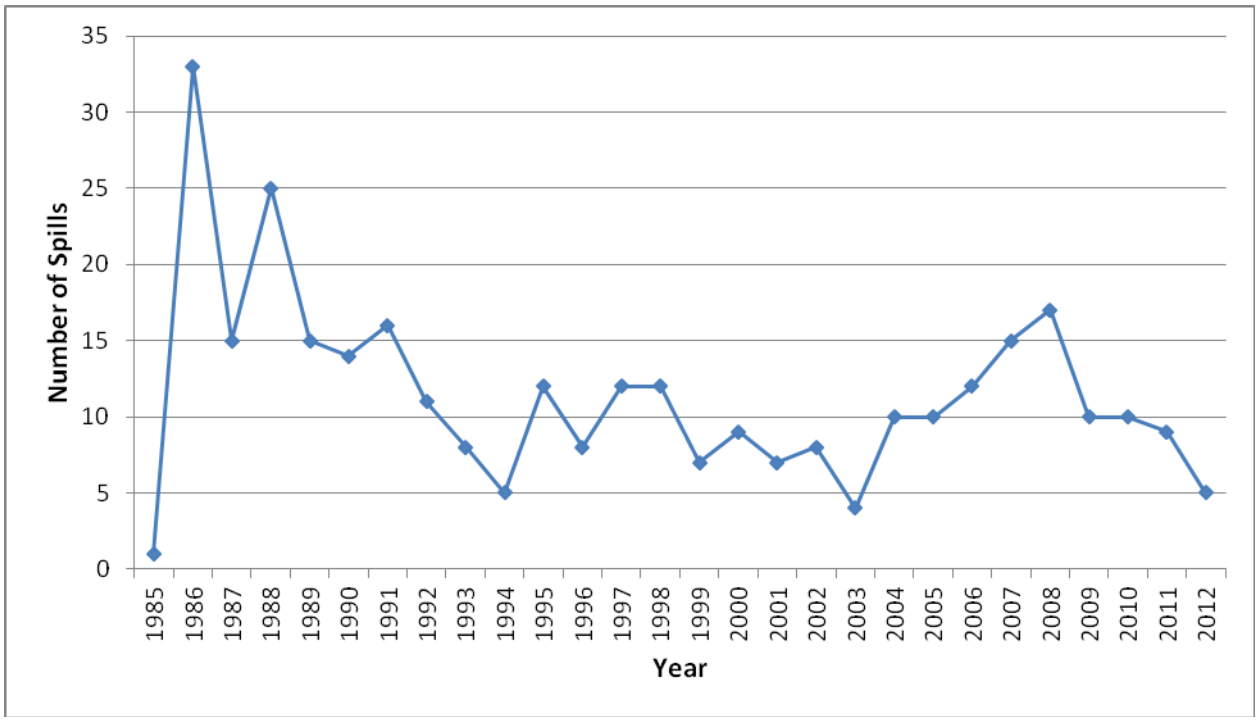
A spill analysis was completed for oil spills greater than 55 gallons at Kuparuk since facility startup in 1985 to 2012. Figure 2-1 illustrates the overall trend of number of incidents at Kuparuk over more than 25 years. Figure 2-2 includes a series of bar graphs that show the relationship between source and volume in five-year increments, and source and frequency in five-year increments. Table 2-3 shows potential major sources of spills are from tanks, fittings/seals/connections, pipe/flowlines/hardlines, and heavy equipment/mobile equipment/vehicles. The major spill sources, as shown in Figure 2-2, illustrate a general trend of decreasing in both frequency of spills and volume over the years. The history of known spills at Kuparuk since 1985 is presented in Appendix C, Table C-1. Copies of records shall be provided to ADEC upon request.

The history of known discharges for all spills to tundra and/or water in the Kuparuk Field since 1986 is included in Appendix C, Table C-2. This table includes the information outlined in 40 CFR Part 112, Appendix F, Section 1.4.4, for spills that are identified by 40 CFR Part 110.

Several measures are employed to minimize and mitigate the reoccurrence of spills on the North Slope. Root Cause Failure Analysis investigations are conducted on all significant spills with lessons learned that are shared with supervisors of affected workgroups. Environmental staff attends project kick-off and operations support meetings where spill mitigation measures and reporting procedures are discussed. Environmental staff also works with responsible parties to ensure timely and accurate reporting and cleanup of spills.

CPAI promotes spill prevention by encouraging proactive involvement and knowledge sharing through spill prevention programs and awareness training or communication in Kuparuk. As part of this process, workgroups are encouraged to analyze spill data and continue to take mitigative measures to reduce events. Job-specific prevention tools may be created by each workgroup based on their evaluation of tasks and spill potential.

To mitigate spills related to known spill causes, CPAI has employed a computerized PM program and has developed and implemented CPAI's corrosion strategy and Tank Management and Integrity Program, which employs automated leak detection and monitoring systems and requires personnel to conduct regular visual inspections on regulated tanks and piping.



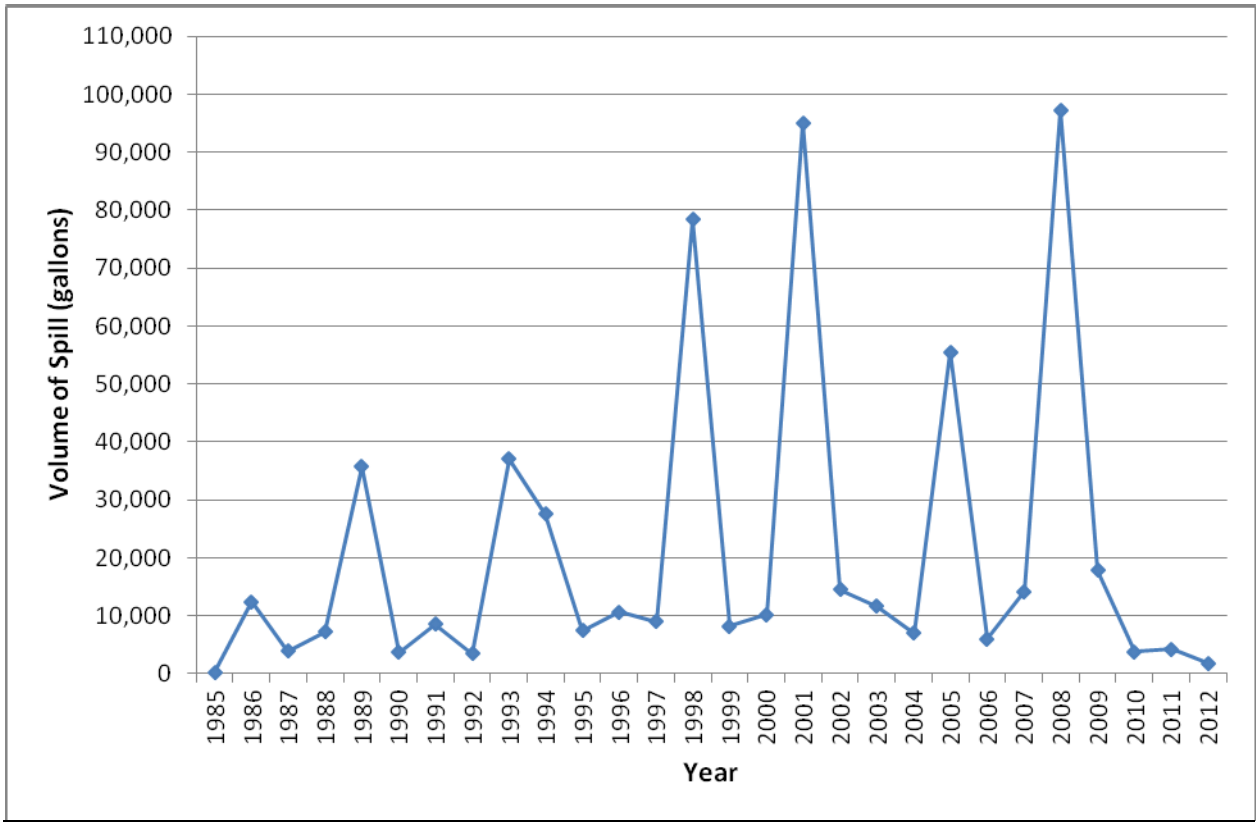


FIGURE 2-1: NUMBER OF SPILL INCIDENTS AND SPILL VOLUME AT KUPARUK 1985 – 2012

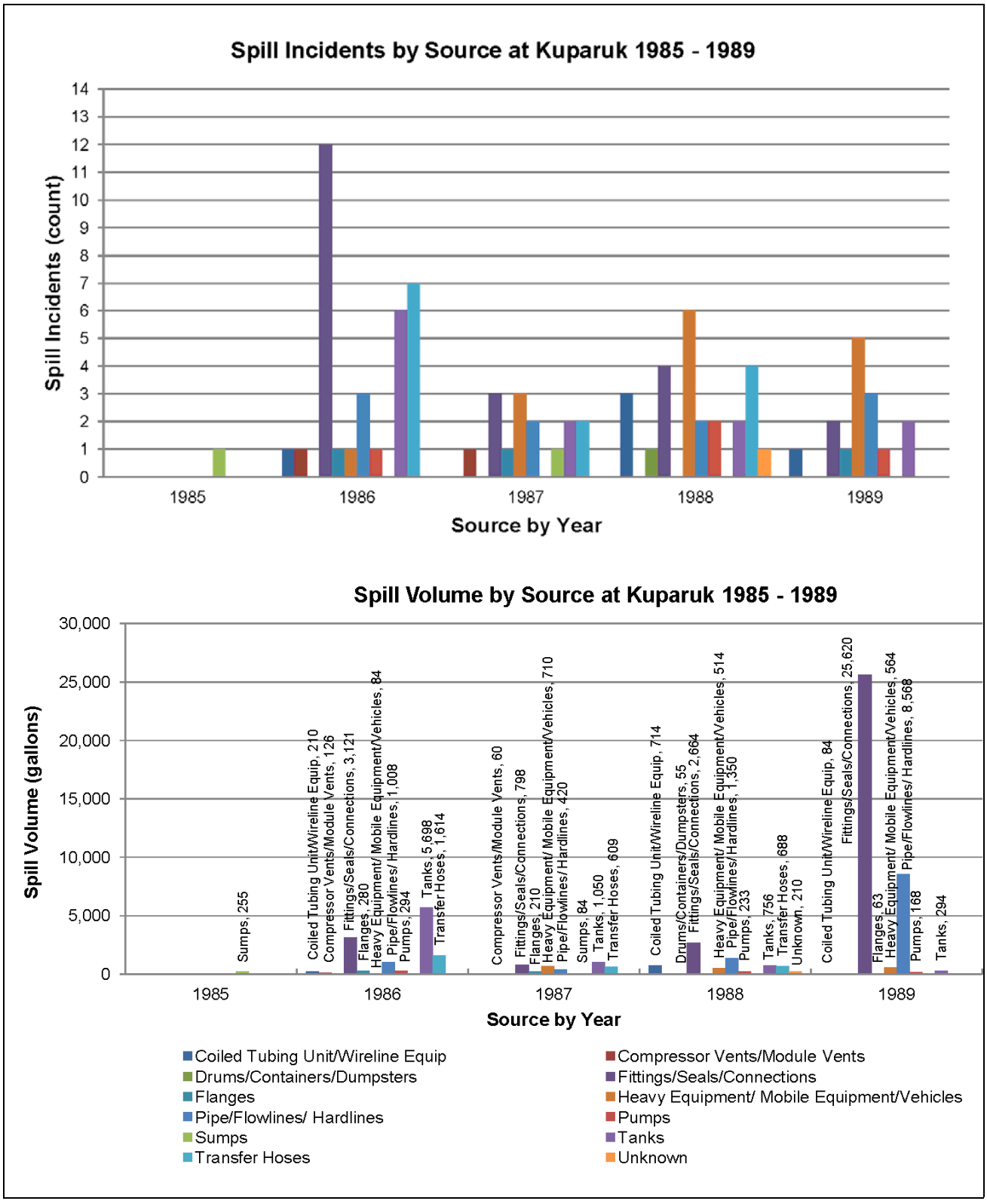


FIGURE 2-2: SPILL INCIDENTS AND VOLUME BY SOURCE 1985 – 2012

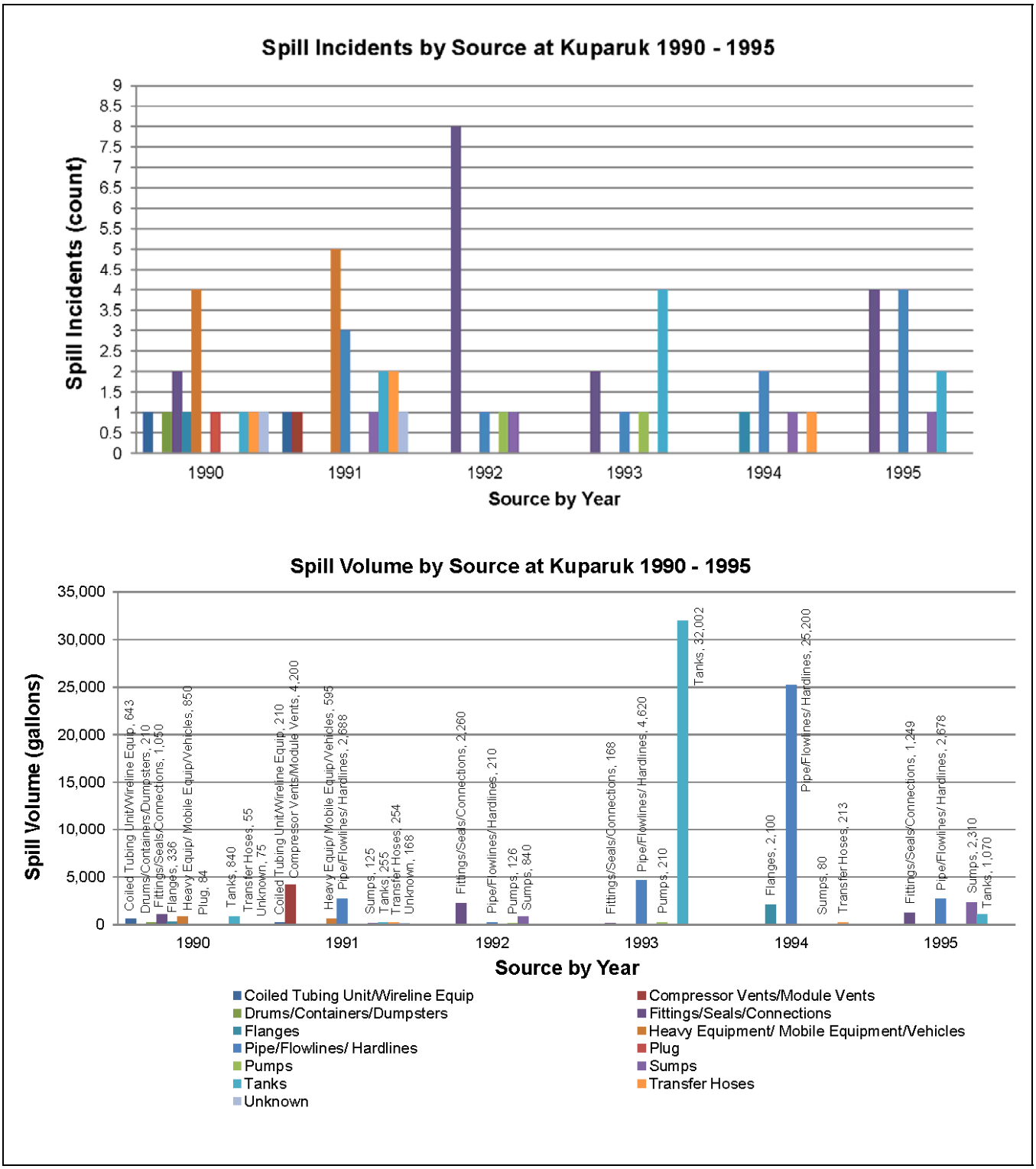


FIGURE 2-2 (CONTINUED): SPILL INCIDENTS AND VOLUME BY SOURCE 1985 – 2012

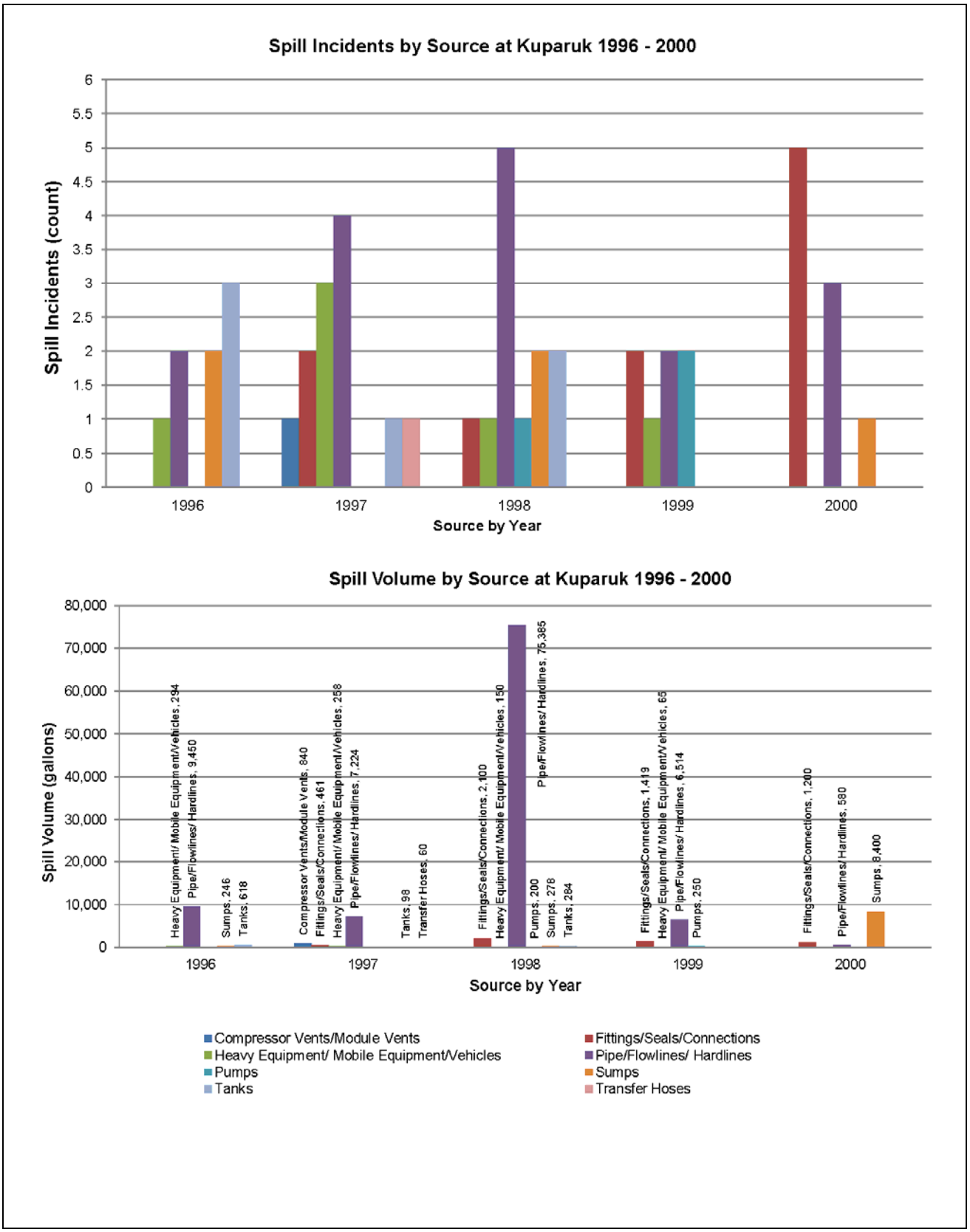


FIGURE 2-2 (CONTINUED): SPILL INCIDENTS AND VOLUME BY SOURCE 1985 – 2012

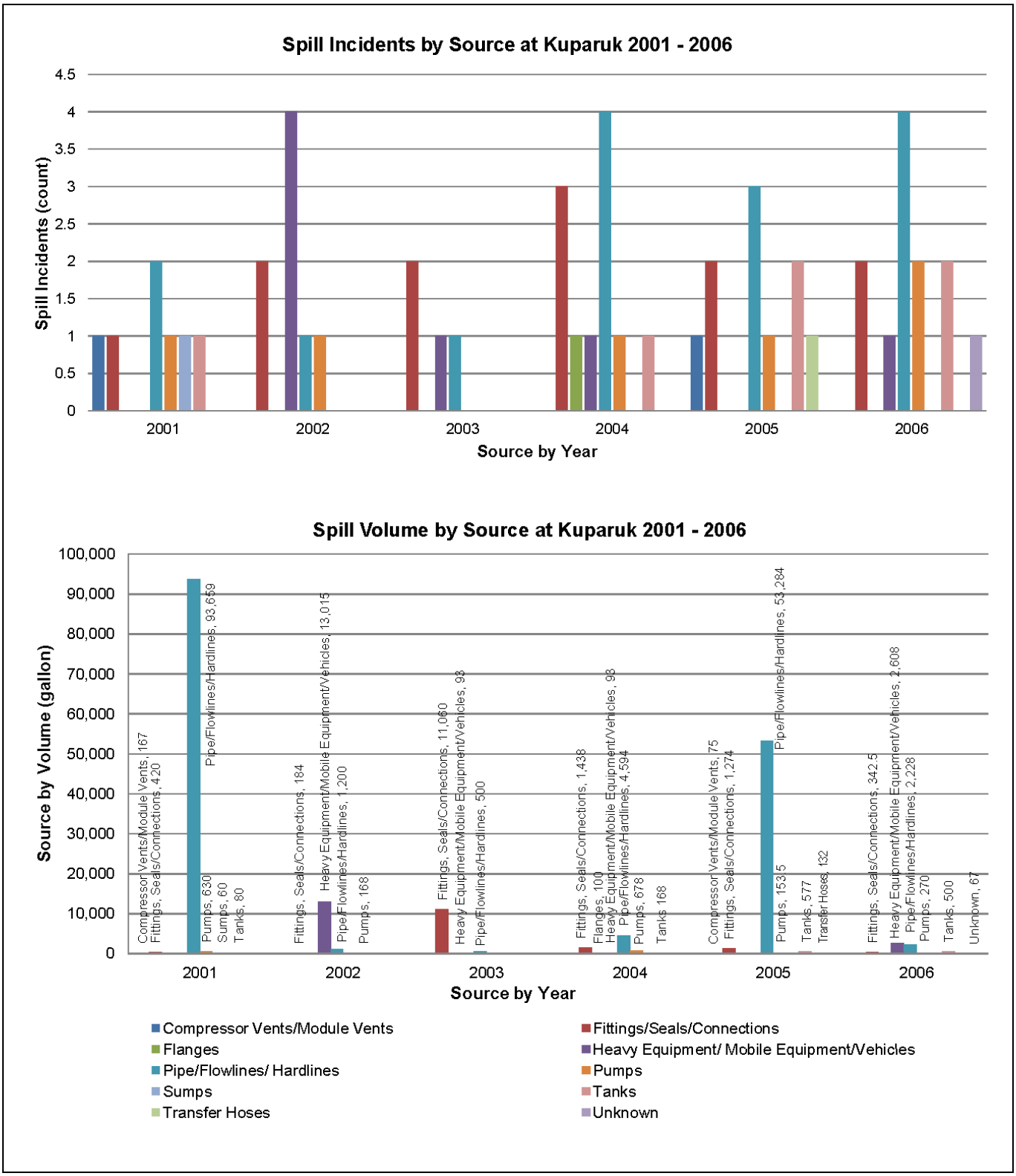
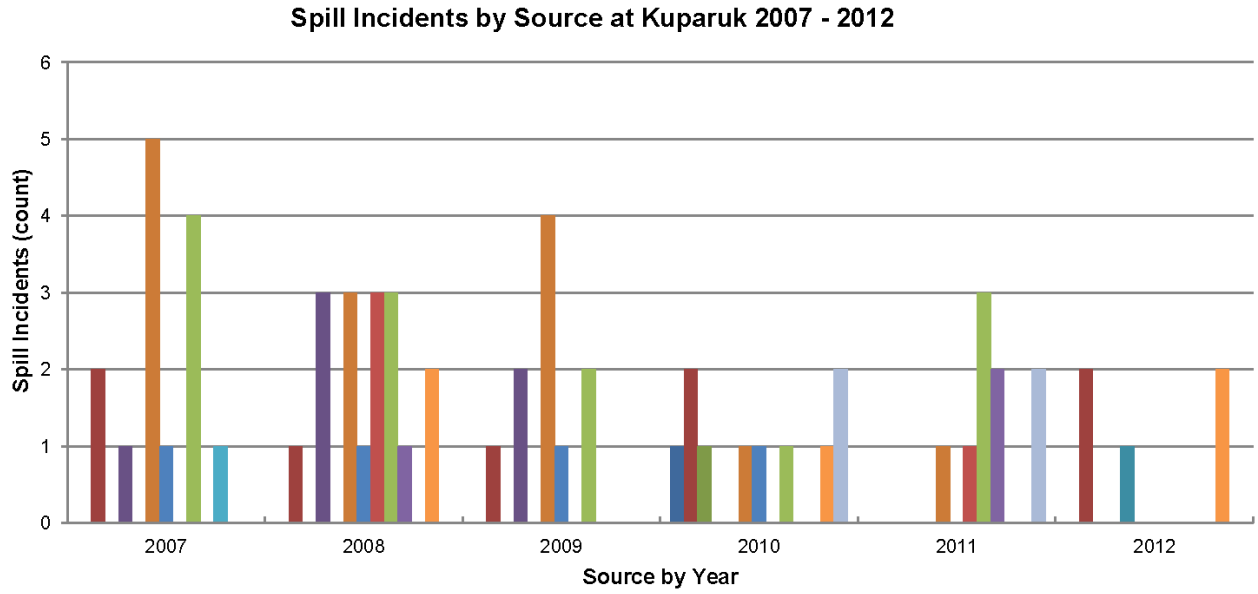


FIGURE 2-2 (CONTINUED): SPILL INCIDENTS AND VOLUME BY SOURCE 1985 – 2012



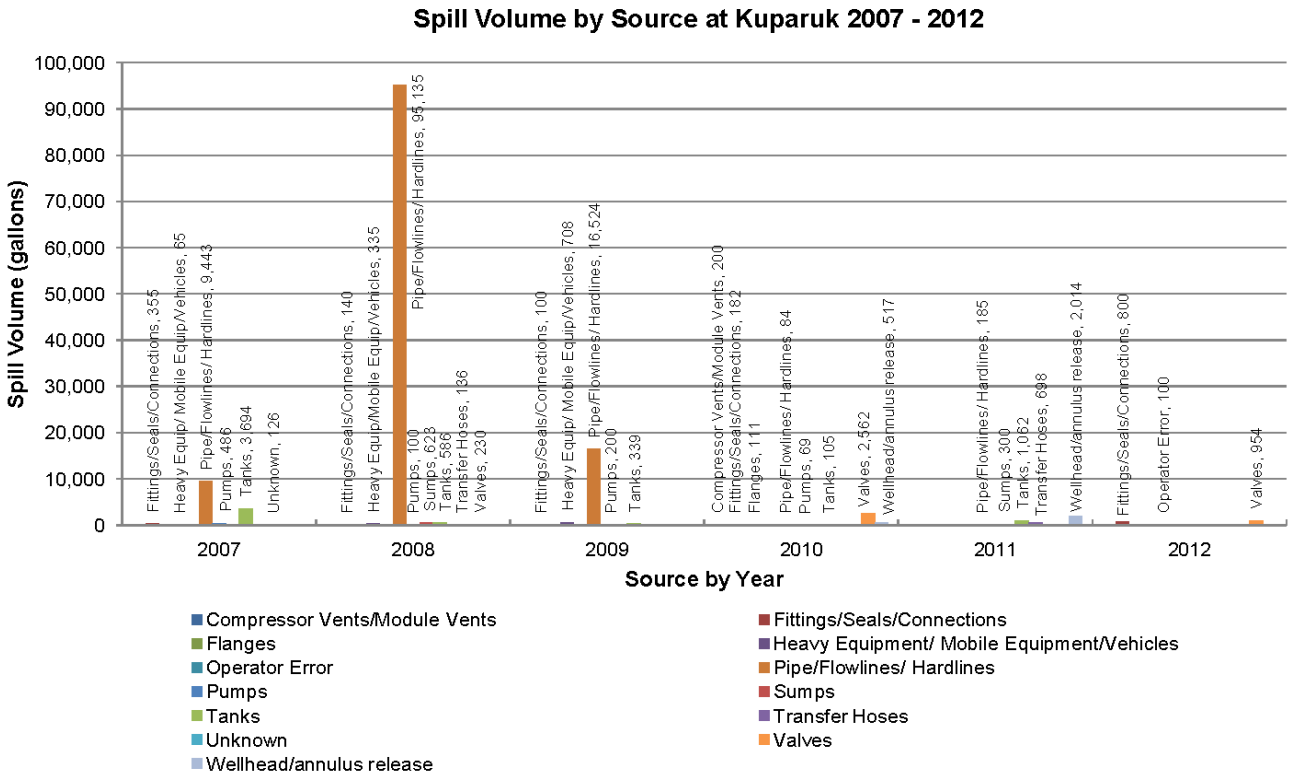


FIGURE 2-2 (CONTINUED): SPILL INCIDENTS AND VOLUME BY SOURCE 1985 – 2012

2.3 POTENTIAL DISCHARGE ANALYSIS [18 AAC 75.425(e)(2)(C)]

This section describes the potential for oil discharges by facilities at Kuparuk and provides the approximate volumes of oil stored or produced in each area. Response scenarios, including response planning volumes, are presented in Section 1.6.3 and are not duplicated here.

Based on the discharge history, potential oil spills at Kuparuk can be grouped according to four major locations: drill sites, CPFs, roads, and tundra. Major sources of spills at drill sites and CPFs are tanks, transfer hoses, pumps, and fittings seals and connections. Major sources that may impact roads and tundra are truck rollovers, well blowouts, and pipelines. Table 2-4 gives the potential cause, product, size, duration, and actions taken to prevent major discharges from tanks, fuel transfer hoses, pumps, fittings seals and connections, truck rollovers, and well blowouts. Table 2-4 through Table 2-6 summarize potential discharges from pipelines.

A review of Kuparuk's Spill History (Appendix C, Table C-1) reveals that, over time, releases from flowlines due to external and internal corrosion have increased at Kuparuk. Flowline releases are of particular concern because flowlines hold a large volume of liquid and are located over tundra, so releases from these pipelines typically result in impacts to tundra. As a result of these incidents, CPAI has significantly modified the corrosion control program to include increased inspection and monitoring of flowlines. This program, now referred to as the CPAI corrosion strategy, is discussed in detail in Section 2.1.6. Inspection and monitoring data are continually analyzed to determine the effectiveness of the program and identify areas for improvement.

Low-pressure sensing devices at the drill sites and associated CPF would detect a leak from production or water injection pipelines. Elevated pipelines adjacent to the road system of the Kuparuk Field allow production or Security personnel routinely touring the field to visually detect small leaks from failure of pipelines, valves, or tie-in connections. In the event of pipeline failure, production personnel will isolate the damaged section by closing the necessary valves to prevent further discharge from production or backflow potential.

Reaction time to isolate pipeline sections varies and is a factor in predicting spill volume potential. Table 2-4, Table 2-5, and Table 2-6 indicate the approximate calculated volumes of individual pipeline sections. It is difficult to predict the rate or spill potential for any given pipeline beyond the immediate volume of the affected pipeline. Spur lines tied to major trunk lines likely would drain to the pipeline failure point. Continuous production from drill sites would be stopped upon discovery and identification of the failure. Response would be from visual observations of the pipelines by production or contract personnel present in the field or from the low-pressure alarms. It is unlikely the entire volume would be drained due to the frequent elevation changes of the pipelines.

The volume of discharge from a corrosion leak is based on a rough order-of-magnitude calculation of fluid flow through a small corrosion-hole failure in a field crude transport line. With the hole area constant and depending on the pressure, the calculations shown in Table 2-4, Table 2-5, and Table 2-6 incorporate several conservative assumptions.

The following general assumptions were made:

- A leak hole area equivalent to a 1/2-inch-diameter round hole (typical size is 1/16 inch to 1/8 inch);
- A continuous liquid-packed condition over the leak hole, with hole orientation at the bottom of the pipe;

- 24-hour leak detection time (1/2-inch fluid stream should be very visible);
- No frictional losses in pipe or through the hole area; and
- Continuous flow through the leak hole, not intermittent fluid and gas (i.e., slug flow).

Because these are all conservative (worst-case) assumptions, most corrosion leaks would actually result in discharges less than those shown in Table 2-4, Table 2-5, and Table 2-6.

TABLE 2-3:
POTENTIAL DISCHARGES FROM MAJOR SOURCES AT KUPARUK

SOURCE	CAUSE	PRODUCT	SIZE (bbl)	DURATION	ACTIONS TAKEN TO PREVENT POTENTIAL DISCHARGE
Oil Storage Tank	Tank Rupture	Diesel		Instantaneous	Secondary containment, overfill protection devices, and the CPAI Tank Management and Integrity Program.
Fuel Transfer Hose	Hose Rupture	Diesel		Instantaneous	Visual inspection, PM program, and fluid transfer procedure.
Pumps	Equipment Failure	Crude, Produced Water, Oil-Based Drilling Mud		Instantaneous	PM program.
Fittings, Seals, and Connections	Equipment Failure	Hydraulic Fluid, Oil-Based Drilling Mud, Crude, Produced Water, or Diesel		Instantaneous	Cold weather operating restrictions, visual inspection, PM program, and fluid transfer procedure.
Truck Rollovers	Weather Conditions, Operator Error	Diesel		<1 hour	Driver training and winter weather travel restrictions.
Well Blowout	Loss of Well Control	Crude		15 days	CPAI Drilling and Wells Emergency Management Plan, BOP equipment and safety valve inspection and maintenance.

TABLE 2-4:
POTENTIAL DISCHARGE CPF-1 PIPELINES
PRODUCED OIL, WET OIL, ENHANCED OIL RECOVERY, OIL SALES

FROM	TO	PIPE DIAMETER (inches)	LENGTH (feet)	VOLUME (bbl)	POTENTIAL DISCHARGE (bbl)*	BLOCK VALVE LOCATIONS	ACTIONS TAKEN TO PREVENT POTENTIAL DISCHARGE
PRODUCED OIL							
							Engineering design, corrosion control program, and visual inspections
							Engineering design, corrosion control program, and visual inspections
							Engineering design, corrosion control program, and visual inspections
							Engineering design, corrosion control program, and visual inspections
							Engineering design, corrosion control program, and visual inspections
							Engineering design, corrosion control program, and visual inspections
							Engineering design, corrosion control program, and visual inspections
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							Engineering design, corrosion control program, and visual inspections
							Engineering design, corrosion control program, and visual inspections
							Engineering design, corrosion control program, and visual inspections
							Engineering design, corrosion control program, and visual inspections
							Engineering design, corrosion control program, and visual inspections

TABLE 2-4 (CONTINUED):
POTENTIAL DISCHARGE CPF-1 PIPELINES
PRODUCED OIL, WET OIL, ENHANCED OIL RECOVERY, OIL SALES

FROM	TO	PIPE DIAMETER (inches)	LENGTH (feet)	VOLUME (bbl)	POTENTIAL DISCHARGE (bbl)*	BLOCK VALVE LOCATIONS	ACTIONS TAKEN TO PREVENT POTENTIAL DISCHARGE
							Engineering design, corrosion control program, and visual inspections
							Engineering design, corrosion control program, and visual inspections
							Engineering design, corrosion control program, leak detection system, and visual surveillance
							Engineering design, corrosion control program, and visual inspections
							Engineering design, corrosion control program, and visual inspections
							Engineering design, corrosion control program, and visual inspections
							Engineering design, corrosion control program, and visual inspections
							Engineering design, corrosion control program, and visual inspections
							Engineering design, corrosion control program, and visual inspections
							Engineering design, corrosion control program, and visual inspections
							Engineering design, corrosion control program, and visual inspections
							Engineering design, corrosion control program, and visual inspections

TABLE 2-4 (CONTINUED):
POTENTIAL DISCHARGE CPF-1 PIPELINES
PRODUCED OIL, WET OIL, ENHANCED OIL RECOVERY, OIL SALES

FROM	TO	PIPE DIAMETER (inches)	LENGTH (feet)	VOLUME (bbl)	POTENTIAL DISCHARGE (bbl)*	BLOCK VALVE LOCATIONS	ACTIONS TAKEN TO PREVENT POTENTIAL DISCHARGE
							Engineering design, corrosion control program, and visual inspections
							Engineering design, corrosion control program, and visual inspections
							Engineering design, corrosion control program, and visual inspections
							Engineering design, corrosion control program, and visual inspections
							Engineering design, corrosion control program, and visual inspections
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							Engineering design, corrosion control program, and visual inspections
							Engineering design, corrosion control program, and visual inspections
							Engineering design, corrosion control program, and visual inspections
							Engineering design, corrosion control program, and visual inspections

TABLE 2-4 (CONTINUED):
POTENTIAL DISCHARGE CPF-1 PIPELINES
PRODUCED OIL, WET OIL, ENHANCED OIL RECOVERY, OIL SALES

FROM	TO	PIPE DIAMETER (inches)	LENGTH (feet)	VOLUME (bbl)	POTENTIAL DISCHARGE (bbl)*	BLOCK VALVE LOCATIONS	ACTIONS TAKEN TO PREVENT POTENTIAL DISCHARGE
							Engineering design, corrosion control program, and visual inspections
							Engineering design, corrosion control program, and visual inspections
							Engineering design, corrosion control program, and visual inspections

TABLE 2-5:
POTENTIAL DISCHARGE CPF-2 PIPELINES
PRODUCED OIL, WET OIL, ENHANCED OIL RECOVERY, OIL SALES

FROM	TO	PIPE DIAMETER (inches)	LENGTH (feet)	VOLUME (bbl)	POTENTIAL DISCHARGE (bbl)	BLOCK VALVE LOCATIONS	ACTIONS TAKEN TO PREVENT POTENTIAL DISCHARGE
PRODUCED OIL							
							Engineering design, corrosion control program, and visual inspections
							Engineering design, corrosion control program, and visual inspections
							Engineering design, corrosion control program, and visual inspections
							Engineering design, corrosion control program, and visual inspections
							Engineering design, corrosion control program, and visual inspections
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							Engineering design, corrosion control program, and visual inspections
							Engineering design, corrosion control program, and visual inspections
							Engineering design, corrosion control program, and visual inspections
							Engineering design, corrosion control program, and visual inspections

TABLE 2-5 (CONTINUED):
POTENTIAL DISCHARGE CPF-2 PIPELINES
PRODUCED OIL, WET OIL, ENHANCED OIL RECOVERY, OIL SALES

FROM	TO	PIPE DIAMETER (inches)	LENGTH (feet)	VOLUME (bbl)	POTENTIAL DISCHARGE (bbl)	BLOCK VALVE LOCATIONS	ACTIONS TAKEN TO PREVENT POTENTIAL DISCHARGE
							Engineering design, corrosion control program, and visual inspections
							Engineering design, corrosion control program, and visual inspections
							Engineering design, corrosion control program, and visual inspections
							Engineering design, corrosion control program, and visual inspections
							Engineering design, corrosion control program, and visual inspections
							Engineering design, corrosion control program, and visual inspections
							Engineering design, corrosion control program, and visual inspections
							Engineering design, corrosion control program, and visual inspections
							Engineering design, corrosion control program, and visual inspections
							Engineering design, corrosion control program, and visual inspections
							Engineering design, corrosion control program, and visual inspections
							Engineering design, corrosion control program, and visual inspections

TABLE 2-5 (CONTINUED):
POTENTIAL DISCHARGE CPF-2 PIPELINES
PRODUCED OIL, WET OIL, ENHANCED OIL RECOVERY, OIL SALES

FROM	TO	PIPE DIAMETER (inches)	LENGTH (feet)	VOLUME (bbl)	POTENTIAL DISCHARGE (bbl)	BLOCK VALVE LOCATIONS	ACTIONS TAKEN TO PREVENT POTENTIAL DISCHARGE
ENHANCED OIL RECOVERY							
							Engineering design, corrosion control program, and visual inspections
							Engineering design, corrosion control program, and visual inspections
							Engineering design, corrosion control program, and visual inspections
							Engineering design, corrosion control program, and visual inspections
							Engineering design, corrosion control program, and visual inspections
							Engineering design, corrosion control program, and visual inspections
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							Engineering design, corrosion control program, and visual inspections
							Engineering design, corrosion control program, and visual inspections
							Engineering design, corrosion control program, and visual inspections
							Engineering design, corrosion control program, and visual inspections
							Engineering design, corrosion control program, and visual inspections

TABLE 2-5 (CONTINUED):
POTENTIAL DISCHARGE CPF-2 PIPELINES
PRODUCED OIL, WET OIL, ENHANCED OIL RECOVERY, OIL SALES

FROM	TO	PIPE DIAMETER (inches)	LENGTH (feet)	VOLUME (bbl)	POTENTIAL DISCHARGE (bbl)	BLOCK VALVE LOCATIONS	ACTIONS TAKEN TO PREVENT POTENTIAL DISCHARGE
							Engineering design, corrosion control program, and visual inspections
							Engineering design, corrosion control program, and visual inspections
							Engineering design, corrosion control program, and visual inspections
							Engineering design, corrosion control program, and visual inspections
							Engineering design, corrosion control program, and visual inspections
							Engineering design, corrosion control program, and visual inspections
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							Engineering design, corrosion control program, and visual inspections
							Engineering design, corrosion control program, and visual inspections
							Engineering design, corrosion control program, and visual inspections
							Engineering design, corrosion control program, and visual inspections

TABLE 2-6:
POTENTIAL DISCHARGE CPF-3 PIPELINES
PRODUCED OIL, WET OIL, ENHANCED OIL RECOVERY

FROM	TO	PIPE DIAMETER (inches)	LENGTH (feet)	VOLUME (bbl)	POTENTIAL DISCHARGE (bbl)	BLOCK VALVE LOCATIONS	ACTIONS TAKEN TO PREVENT POTENTIAL DISCHARGE
PRODUCED OIL							
							Engineering design, corrosion control program, and visual inspections
							Engineering design, corrosion control program, and visual inspections
							Engineering design, corrosion control program, and visual inspections
							Engineering design, corrosion control program, and visual inspections
							Engineering design, corrosion control program, and visual inspections
							Engineering design, corrosion control program, and visual inspections
							Engineering design, corrosion control program, and visual inspections
							Engineering design, corrosion control program, and visual inspections
							Engineering design, corrosion control program, and visual inspections
							Engineering design, corrosion control program, and visual inspections
							Engineering design, corrosion control program, and visual inspections

TABLE 2-6 (CONTINUED):
POTENTIAL DISCHARGE CPF-3 PIPELINES
PRODUCED OIL, WET OIL, ENHANCED OIL RECOVERY

FROM	TO	PIPE DIAMETER (inches)	LENGTH (feet)	VOLUME (bbl)	POTENTIAL DISCHARGE (bbl)	BLOCK VALVE LOCATIONS	ACTIONS TAKEN TO PREVENT POTENTIAL DISCHARGE
							Engineering design, corrosion control program, and visual inspections
							Engineering design, corrosion control program, and visual inspections
							Engineering design, corrosion control program, and visual inspections
							Engineering design, corrosion control program, and visual inspections
							Engineering design, corrosion control program, and visual inspections
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							Engineering design, corrosion control program, and visual inspections
							Engineering design, corrosion control program, and visual inspections
							Engineering design, corrosion control program, and visual inspections

TABLE 2-6 (CONTINUED):
POTENTIAL DISCHARGE CPF-3 PIPELINES
PRODUCED OIL, WET OIL, ENHANCED OIL RECOVERY

FROM	TO	PIPE DIAMETER (inches)	LENGTH (feet)	VOLUME (bbl)	POTENTIAL DISCHARGE (bbl)	BLOCK VALVE LOCATIONS	ACTIONS TAKEN TO PREVENT POTENTIAL DISCHARGE
							Engineering design, corrosion control program, and visual inspections
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							Engineering design, corrosion control program, and visual inspections

TABLE 2-6 (CONTINUED):
POTENTIAL DISCHARGE CPF-3 PIPELINES
PRODUCED OIL, WET OIL, ENHANCED OIL RECOVERY

FROM	TO	PIPE DIAMETER (inches)	LENGTH (feet)	VOLUME (bbl)	POTENTIAL DISCHARGE (bbl)	BLOCK VALVE LOCATIONS	ACTIONS TAKEN TO PREVENT POTENTIAL DISCHARGE
							Engineering design, corrosion control program, and visual inspections
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							Engineering design, corrosion control program, and visual inspections

2.4 CONDITIONS INCREASING RISK OF DISCHARGE [18 AAC 75.425(e)(2)(D)]

Conditions specific to CPAI's North Slope operations that potentially increase the risk of discharge, and actions taken to eliminate or minimize identified risks are summarized below:

- **Temperature:** Heat may cause gases to expand, increasing the likelihood of discharge. North Slope facilities are engineered to accommodate temperature fluctuations.
- **Weather Conditions:** Icy roads, white-out conditions, and cold snaps present obvious threats to field operations. CPAI Security's strict adherence to vehicle safety, and speed limits, and the posting of warning signs minimize the potential for vehicular accidents that may result in a spill. In addition, North Slope facilities are engineered to withstand arctic conditions.
- **Traffic Patterns:** Changes in traffic patterns may increase the risk of vehicles colliding with well lines. Enforced speed limits and the posting of warning signs or traffic cones help minimize the potential for vehicular accidents that may result in a spill.
- **High Water/Ice:** High water and/or ice during break-up increase the risk of discharge over river crossings. The Kuparuk Pipeline crosses the Kuparuk, Sakonowak, and Putuligayuk rivers. The pipeline support members have been engineered to withstand the worst-case ice conditions for the river crossings.
- **Age of the Facilities:** As the Kuparuk Field ages, the discharge potential increases. To minimize spills related to aging facilities, CPAI uses a computerized PM program, has developed and implemented CPAI’s corrosion strategy and Tank Management and Integrity Program, performs valve inspections in accordance with AOGCC regulations, employs automated leak detection and monitoring systems, and conducts regular visual inspections on regulated tanks and piping.

2.5 DISCHARGE DETECTION [18 AAC 75.425(e)(2)(E)]

2.5.1 Leak Detection Methods for Facilities

The Kuparuk Field pipeline system contains approximately 414 miles of actual pipe (not including gas lines) of various dimensions and operating pressures. Most of these pipelines run parallel to each other, use the same support members, and interconnect individual wells with drill site facilities, and drill site facilities with CPFs. Two methods of leak detection are used: visual surveillance and monitoring, and pressure-sensing devices.

Visual Surveillance and Monitoring

A system of visual surveillance and monitoring by numerous personnel has been developed and maintained for all Kuparuk facilities and pipelines. Details of the various personnel involved in this monitoring are provided below, along with a description of the type and frequency of monitoring that they provide.

Drill Site Operator: Drill Site Operator responsibilities include routine inspection of wells, well houses, pad, flowlines, and associated drill site facilities weather, snow, and road conditions permitting. These inspections include:

- Inspection of the hydraulic panels for indications of hydraulic fluid leak;
- Contaminated gravel within the well house that would indicate a leak from the wellhead or the hydraulic panel;
- Containment integrity of the hydraulic panel secondary containment; and
- Flowlines and support members.

Records of the routine well house inspections are documented, at a minimum, weekly. Inspection records will be kept on file for five years, as required by 18 AAC 75.007(h). All spills noted during these inspections will be properly reported according to the guidelines described in Section 1.2 of this plan. Initial response actions will be in accordance with scope and duration detailed in 18 AAC 75, Article 3. Follow-up maintenance or corrective actions noted during the inspections will be entered into the daily operator log and then transferred to the maintenance planning database for prioritization and scheduling.

Radiographic and Ultrasonic Testing Personnel: Personnel monitor in-field produced crude flowlines and valves with non-destructive testing. Monitoring is focused in areas and on pieces of equipment most susceptible to erosion and corrosion. Additional testing is added as conditions and test results indicate.

Valve Inspection: Quarterly inspections are conducted of all over-tundra produced crude flowline valves. Inspection records are kept on file.

Valve Lubrication and Inspection Crew: All in-field produced crude flowline valves between drill site facilities and production facilities are inspected and lubricated annually. Inspection documentation is kept on file.

Incidental Observers: Incidental observations occur daily (conditions permitting) at irregular intervals by varying combinations of personnel including: CPAI maintenance crews, environmental staff, supervisors, state inspectors, preventive maintenance crews, vendors, CPAI aviation crews, and other personnel conducting business with CPAI.

(b) (7)(F), (b) (3)

[redacted]

Visual Inspection Leak Detection

With the exception of the line segments that pass through the various culverts below road crossings, the Kuparuk Pipeline is supported above ground on vertical support members (VSMs). Much of the pipeline is in close proximity to the road system.

Visual inspections are carried out by either flying over or driving along the pipelines to ensure minor leaks are found and corrected as soon as possible. Visual aerial surveillance of DOT-regulated pipelines is conducted weekly (safety and weather permitting) in accordance with 18 AAC 75.055(a)(3); a log is completed by surveillance personnel. Ground-based visual inspections occur several times a week (safety and weather permitting) and a log is completed by Security personnel and filed in the Kuparuk Environmental files. As an added measure of leak detection, aerial surveillance is conducted weekly using the FLIR-equipped Twin Otter, weather and safety conditions permitting. FLIR surveillance schedules may be delayed due to emergency use of the FLIR outside of KRU, or mechanical failure or routine maintenance of the Twin Otter or FLIR. Therefore, CPAI relies on weekly visual aerial surveillance to meet requirements of 18 AAC 75.055(a)(3).

If a minor leak is suspected, it is the responsibility of the CPF-3 board operator to dispatch qualified personnel to visually check the line. The board operator will dispatch personnel directly and/or direct others to dispatch appropriate personnel. Radio contact with the CPF-3 board operator will be maintained so that appropriate action can be taken to mitigate a leak if discovered. Adverse weather conditions may prevent visual inspections and detection of minor leaks at rates below those that can be detected by electronic leak detection methods.

2.6 WAIVERS [18AAC 75.425(e)(2)(F)]

Waivers applicable to Kuparuk field and pipeline operations are included following this section. Waiver content is as follows:

- October 27, 2014. Tank Design Approval #2014-01.
- April 8, 2014. Waiver for tank truck unloading area secondary containment system located near the CPAI Kuparuk Airport V-702 aircraft fuel tank.
- February 28, 2013. Tank Design Approval #2013-01, Revision 1.
- December 14, 2011. Waiver not required for seasonal or short-term temporary tank truck unloading area for CPF-3 Diesel Storage Tank T-EF03.
- June 22, 2011. Waiver not required for seasonal or short-term temporary tank truck unloading areas for CPF-1, 2, 3 Lube oil Tanks and CPF-3 Slope Oil Tank.
- February 19, 2009. Waiver from the Requirements for Secondary Containment – Tank T-AN105.
- September 13, 2007. Waiver for Flow Line Marker Requirements
- June 22, 2005. Waiver of Oil Storage Tank Construction Requirement/Approval for Tank Use.
- March 23, 2005. Waiver of Secondary Containment Area Capacity Requirements for Doyon Drill Rig 141 Fuel Tank.
- February 13, 2004. Waiver of Secondary Containment Area Capacity Requirements for Tanks T1-101, T-2201, T-2202, T-CM01, T-CM02, and T-EF52.
- November 13, 2003. Waiver for Use of Alternate Materials, Tank T-2201.
- February 26, 2003. Waiver of Oil Storage Tank Construction Standards.
- October 2, 2002. Approval of Amendment for Alternate Tank Construction Standard, UL-142 Tank at DS-2N.
- April 18, 1999. ARCO Alaska, Inc. Below-Grade Piping Corrosion Control Program.
- October 26, 1998. Corrosion Control Program for Buried and Below-Grade Piping.

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THE STATE of ALASKA
GOVERNOR SEAN PARNELL

Department of Environmental Conservation

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October 27, 2014

File No.: 305.35
(CPAI-Alpine, KRU, NSX)

Jeanie Shifflett
Emergency Planning Coordinator
ConocoPhillips Alaska, Inc.
P.O. Box 100360
Anchorage, AK 99510-0360

Subject: **ConocoPhillips Alaska, Inc. Oil Discharge Prevention and Contingency Plans for the Kuparuk River Unit (Plan No. 12-CP-4102), Alpine Development (Plan No. 12-CP-4140), and North Slope Exploration (Plan No. 12-CP-5096). Tank Design Approval #2014-01**

Dear Ms. Shifflett:

The Alaska Department of Environmental Conservation (department) has reviewed ConocoPhillips Alaska, Inc.'s (CPAI) September 25, 2014 request for tank design approval. CPAI requested that the department approve an alternate tank design for portable 400-barrel, rectangular storage tanks owned by Tank-O Alaska, LLC for use by CPAI at its North Slope facilities.

18 AAC 75.066(b)(1) requires that shop-fabricated oil storage tanks be built to specified standards; however, 18 AAC 75.066(b)(2) allows alternate tank design if the design is certified by a registered engineer and is approved by the department as equivalent to a design for a standard listed in 18 AAC 75.066(b)(1). Detailed information about the tank design was submitted on a CD, along with inspections and reports for two example tanks. The tank design was engineered by PCI Manufacturing, LLC. A conceptual review was conducted by the Industry Preparedness Program's Pipeline and Tank Integrity Section on the following design information:

- Tank drawings
- Welding Procedure Specifications and Welder Qualifications
- Welding Inspection Reports and Hydrotest and Air Test Reports
- Materials Summary and Test Reports
- Structural Calculations
- Coating Inspection Reports
- Coating Data Sheets
- Inspector Qualifications

Review of the design submittal substantiates that department approval of the tank design as equivalent to a standard listed in 18 AAC 75.066(b)(2) is warranted. A summary of findings is outlined below:

- The 400-barrel steel, horizontal, rectangular, double-wall, open-top tank is reported to have been designed and constructed to American Petroleum Institute (API) 650, *Welded Steel Tanks for Oil Storage*, including modifications in Appendix J for shop-assembled storage tanks, which meets the requirements of 18 AAC 75.066(b).
- The tank meets 18 AAC 75.066(e) by having an interstitial monitoring system, a fixed overfill spill containment system at the fill and dispensing ports, and a system for freeing any contents from the interstitial space.
- Structural calculations were performed and stamped by a licensed Alaska Professional Engineer.
- The construction drawings were approved and stamped by a licensed Alaska Professional Engineer.

The department's review indicates that tanks built per the submitted design criteria should be fit for service for atmospheric, hydrocarbon service. Based on the tank drawings, the tank meets the construction and appurtenance requirements of 18 AAC 75.066. The department approves this design as equivalent to a design for a standard listed in 18 AAC 75.066(b)(1). This alternate construction standard approval, "Tank Design Approval #2014-01," remains valid for tanks built to the design specifications. In the future, as long as there is verification that a tank is being built per this design package, no further evaluation by the department is necessary.

Please be advised that this approval does not relieve you of the responsibility for securing other state, federal, or local approvals or permits, and that you are still required to comply with applicable requirements of 18 AAC 75, Article 1 and all other applicable laws.

If you have any questions, please contact Laurie Silfven at (907) 269-7540 or via email at laurie.silfven@alaska.gov, or myself at (907) 269-7680 or graham.wood@alaska.gov.

Sincerely,

Graham Wood
Section Manager

Electronic cc:

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Ashley Adamczak, ADEC
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Beth Heim, ADEC
Gary Evans, ADEC
Mike Evans, ADEC

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April 8, 2014

File No.: 305.35
(CPAI-Kuparuk)

Jeanie Shifflett
ConocoPhillips Alaska, Inc.
P.O. Box 100360
Anchorage, AK 99510-0360

Subject: **ConocoPhillips Alaska, Inc. - Kuparuk River Unit and Oliktok Pipeline Oil Discharge Prevention and Contingency Plan. Plan Number 12-CP-4102, Waiver for tank truck unloading area secondary containment system located near the ConocoPhillips Alaska, Inc. Kuparuk Airport V-702 aircraft fuel tank: REVISED**

Dear Ms. Shifflett:

The Alaska Department of Environmental Conservation (department) received your March 13, 2014 amendment request to revise the existing waiver for secondary containment requirements due to increased operational demands. ConocoPhillips Alaska, Inc. (CPAI) states the frequency of fuel transfers at the Kuparuk Landing Area (KLA) Tank Truck Loading Area (TTLA) has increased from once per month to two or three times per month due to higher operational demands for aircraft fuel. Fuel requirements have also increased due to increased flights and higher aircraft loads to accommodate the increase in passengers and freight. Relocation of small aircraft to the Alpine base has contributed to the increased fuel usage due to the need for additional aircraft fuel loading contingency requirements for weather diverts. CPAI requests approval of a revised waiver to cover the increase in frequency of fuel transfers at the KLA TTLA.

Conditions of use at the KLA TTLA are as follows:

- Transfers are conducted in accordance with 18 AAC 75.025(f) and (g) as required in the existing waiver; established North Slope transfer procedures for flammable and combustible fluids.
- Transfers are attended by aviation support personnel and the tank truck operator.
- The storage tank and its appurtenances are contained within a secondary containment area in compliance with requirements of 18 AAC 75.075.
- The tank is inspected and tested in accordance with applicable requirements of 18 AAC 75.066
- A spill kit containing sorbent boom (8" x 40' size or similar) will be staged at the KLA to provide an immediate means of containment, in the unlikely event of a large, uncontrolled spill from the tank truck.

Department Findings

Based on the information provided by CPAI for this waiver request, the prevention measures described above, and the waiver conditions below, the department approves this waiver request.

The waiver is subject to the following conditions.

(1) CPAI must ensure that transfer requirements are consistent with 18 AAC 75.025 (f), and (g) to and from areas not protected by secondary containment.

(2) Overfill protection devices must be tested and inspected in accordance with 18 AAC 75.065(l), including liquid level alarms, switches, and valves associated with the Kuparuk airport tank V-702. Testing and inspection documentation must be maintained for verification purposes for 5 years as required in 18 AAC 75.020(e).

(3) Secondary containment inspections must be done twice weekly and documented. These documents must be maintained per 18 AAC 75.020(e) and made available to the department upon request.

(4) Spill response sorbents will be located at the pump control room and the facility is located within a quarter mile from the ACS Spill Response Team warehouse at the CPAI camp.

(5) Established North Slope fuel transfer procedures as described in the *2010 ConocoPhillips Alaska Safety Handbook* for flammable and combustible fluid transfer operations and the *North Slope Fluid Transfer Guidelines* will be followed, and CPAI will ensure that two trained people observe all fuel transfers involving this tank truck unloading area.

(6) This waiver is valid from date of issue forward. Any significant change to tank truck unloading operational procedures or an increase in frequency of tank truck unloading may negate the terms of this waiver and must be reported to the department immediately.

This waiver does not exempt CPAI from any other state, federal, or local requirements that may apply. The department reserves its rights to pursue administrative and judicial remedies for future violations in the event CPAI does not comply with the conditions of this waiver.

Additionally, CPAI shall, within 45 days of receiving this waiver letter, submit an Oil Discharge Prevention and Contingency Plan (plan) amendment to add this waiver to Section 2.6 *Compliance Schedule and Waivers* of the approved plan. The amendment request must also appropriately update Table 2.2 and Appendix B, and Table B-1 in the approved plan.

All terms and conditions of the department's *Letter of Approval* dated March 7, 2013, and the existing *Certificate of Approval* remain in effect. The expiration date of this amendment coincides with the existing plan approval.

Based on the information provided by CPAI and the conditions described above, the department hereby approves this waiver effective April 9, 2014.

APPEAL: This is a final decision. Aggrieved persons with standing may appeal this decision to the Alaska Superior Court within 30 days as provided by the Alaska Rules of Appellate Procedure.

If you have any questions regarding this letters content please feel free to contact Gary Evans at (907) 269-7536 or at gary.evans@alaska.gov.

Sincerely,

Graham Wood
Section Manager

Electronic cc:

Gary Evans, ADEC
Tom DeRuyter, ADEC
Ashley Anderson, ADEC
DNR C-Plan, ADNR
Gordon Brower, NSB
Rhoda Ahmaogak, NSB
Jack Winters, ADFG
Matt Carr, USEPA
Melanie Barber, USDOT
Mike Thompson, JPO
Pam Miller, Northern Alaska Environmental Center
Legal Director, Trustees for Alaska
USCG, Western Alaska Facilities
Planning Manager, Alaska Clean Seas

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Department of Environmental Conservation

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February 28, 2013

File No.: 305.35 (Rev. 1)
(CPAI-Alpine, KRU, NSX)

Jeanie Shifflett
Emergency Planning Coordinator
ConocoPhillips Alaska, Inc.
P.O. Box 100360
Anchorage, AK 99510-0360

Subject: **ConocoPhillips Alaska, Inc. Oil Discharge Prevention and Contingency Plans. Tank Design Approval #2013-01 - Schlumberger Portable Tanks for the Kuparuk River Unit (Plan No. 07-CP-4102), Alpine Development (Plan No. 12-CP-4140), and North Slope Exploration (Plan No. 12-CP-5096). Revision 1**

Dear Ms. Shifflett:

The Alaska Department of Environmental Conservation (department) has reviewed ConocoPhillips Alaska, Inc.'s (CPAI) request for tank design approval dated November 21, 2012. CPAI requested that the department approve an alternate tank design for portable 500-barrel, rectangular storage tanks for use by CPAI at its North Slope facilities.

18 AAC 75.066(b)(1) requires that shop-fabricated oil storage tanks be built to specified standards; however, 18 AAC 75.066(b)(2) allows alternative tank design if the design is certified by a registered engineer and is approved by the department as equivalent to a design for a standard listed in 18 AAC 75.066(b)(1). CPAI submitted a design/construction package for five portable storage tanks owned by Schlumberger Technology Corporation and constructed in 2012. The tank design was engineered and built by Greer Tank and Welding, Inc. A conceptual review was conducted by the Industry Preparedness Program's Pipeline and Tank Integrity Section on the submitted design/construction package which included the following documentation:

- Hydrotest Certificates
- Certificate of Acceptance – Certificate of Compliance
- Welding Procedure Specifications
- Welding Qualification Test Record
- Professional Engineer Stamped Drawings
- Professional Engineer Stamped Structural Calculations
- Tank As-Built Drawings

Review of the design/construction package substantiates that department approval of the tank design as equivalent to a standard listed in 18 AAC 75.066(b)(2) is warranted. A summary of findings is outlined below:

- Structural calculations were performed and stamped by a licensed Alaska Professional Engineer.
- The construction drawings were approved and stamped by a licensed Alaska Professional Engineer.
- As-built drawings confirm design intent.
- The design criteria notes state that tanks were constructed to follow the basic design provisions of American Petroleum Institute (API) 650, *Welded Steel Tanks for Oil Storage*, 11th Edition, including Addendums 1, 2, and 3, and specifically Appendix J, *Shop-Assembled Storage Tanks*, unless deviations were specified. The design criteria notes indicate that API 650 provided the most appropriate guidance, even though this rectangular tank design does not fit the large volume, vertical cylindrical tank configuration typical of API 650.
- Welding documentation appears adequate.
  - Welding procedure specifications are based on American Society of Mechanical Engineers (ASME) IX and American Welding Society (AWS) D1.1 and were signed and stamped by an AWS-certified company representative.
  - Welder and Welding Operator Qualification Test records are signed and stamped by an AWS-certified company representative.
  - 100 percent of welds were specified for visual inspection.
  - 100 percent of butt welds at the wall plate, floor plate, and roof plate were specified for Liquid Penetrant examination.
- Tank inspections in accordance with API 653 were conducted by an API-certified inspector.
- Records indicate the tanks passed hydrostatic testing per Underwriters' Laboratories (UL) 142.

The department's review indicates that tanks built per the submitted procedures should be fit for service for atmospheric, hydrocarbon service. The department approves this design as equivalent to a design for a standard listed in 18 AAC 75.066(b)(1). This alternate construction standard approval, "Tank Design Approval #2013-01," remains valid for tanks built to the design/construction package specifications as long as the tank design and construction specifications are not modified and the tanks are operated within the established design parameters. In the future, as long as there is verification that a tank is being built per this design package, no further evaluation by the department is necessary. We request that CPAI give us advance notice of intended use of tanks built to this design standard.

Please be advised that this approval does not relieve you of the responsibility for securing other state, federal, or local approvals or permits, and that you are still required to comply with applicable requirements of 18 AAC 75, Article 1 and all other applicable laws.

If you have any questions, please contact Laurie Silfven at (907) 269-7540 or via email at laurie.silfven@alaska.gov, or contact me at (907) 269-7680 or graham.wood@alaska.gov.

Sincerely,

Graham Wood
Section Manager

Electronic cc:

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Sam Saengsudham, ADEC
Roger Burleigh, ADEC
Keith Sanfacon, ADEC

STATE OF ALASKA

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December 14, 2011

File No.: 305.35
(CPAI-Kuparuk)

Jeanie Shifflett
ConocoPhillips Alaska, Inc.
P.O. Box 100360
Anchorage, AK 99510-0360

Subject: **ConocoPhillips Alaska, Inc. Kuparuk River Unit and Oliktok Pipeline Oil Discharge Prevention and Contingency Plan. Plan Number 07-CP-4102, Waiver not required for seasonal or short-term temporary tank truck unloading area for CPF3 Diesel Storage Tank T-EF03**

Dear Ms. Shifflett:

The Alaska Department of Conservation (department) has reviewed your November 28, 2011 letter requesting concurrence that a waiver of secondary containment requirements for CPF3 Diesel Tank Truck Loading and Unloading Areas (TTLA) **"do not apply"** to current operations per 18 AAC 75.075(g) for diesel storage tank T-EF03.

The November 28, 2011 letter describes current CPF 3 diesel tank operations and justification for why the TTLA seasonal or short term temporary tank truck operations should apply to this location.

The department sent email confirmation (enclosed) to ConocoPhillips Alaska, Inc. (CPAI) on 12-2-2011 that concurs with the infrequent use approval for this location. This letter is the formal written concurrence that I promised in that email.

[redacted]

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[redacted]

3. CPAI reports that the tank hook-up connection area has existing secondary containment and all load/unloading activities are performed in accordance with CPAI fluid transfer procedures. In particular, visual inspection is required before and after a transfer, and wheel chocks are required to prevent premature vehicular movement.

Any increase in frequency of tank truck unloading at the above described tank area that is not consistent with short-term emergency response, seasonal usage, or short-term temporary usage to meet unusual operation demands must be reported to the department immediately.

If you have questions about this letter, I can be reached at (907) 269-7536.

Sincerely,

Gary Evans
Environmental Program Specialist

Enclosure: Copy of email message from Gary Evans dated 12/2/2011

Scott Pexton, ADEC
Tom DeRuyter, ADEC
Jim Short, CPAI

STATE OF ALASKA

DEPT. OF ENVIRONMENTAL CONSERVATION

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June 22, 2011

File No.: 305.35
(CPAI-Kuparuk)

Jeanie Shifflett
ConocoPhillips Alaska, Inc.
P.O. Box 100360
Anchorage, AK 99510-0360

Subject: **ConocoPhillips Alaska, Inc. Kuparuk River Unit and Oliktok Pipeline Oil Discharge Prevention and Contingency Plan. Plan Number 07-CP-4102, Waiver not required for seasonal or short-term temporary tank truck unloading areas for CPF 1,2,3 Lube Oil Tanks and CPF 3 Slop Oil Tank**

Dear Ms. Shifflett:

The Alaska Department of Conservation (Department) has reviewed your April 6, 2011 letter (enclosed) requesting a waiver of secondary containment requirements for selected Kuparuk Tank Truck Loading and Unloading Areas. The letter describes five specific areas that are used by ConocoPhillips Alaska, Inc (CPAI) at various locations at the Kuparuk oil production facilities. This letter addresses three tank truck unloading areas for Lube Oil tanks at Central Processing Facility (CPF) 1, CPF 2, and CPF 3 and one slop oil tank at CPF 3.

According to the information you provided, the use of the three lube oil tank truck unloading areas occurs an average of once each year to supply oil from tank trucks to the lube oil tanks for facility operational use. The amount of oil delivered by truck to each tank varies. The use of tank trucks may occur during winter exploration activities to unload oil streams to the slop oil tank at CPF 3, but the area is not used on a regular basis.

The following four tank truck unloading areas are determined to be for areas of seasonal usage or short-term temporary usage to meet unusual operation demands and are identified by tank number, tank volume (gallon), and CPAI facility where the tank is located. The requirements of 18 AAC 75.075(g) **do not apply** to unloading areas used for short-term emergency response,

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seasonal usage, or short-term temporary usage to meat unusual operational demands. 18 AAC 75.990 (176).

[redacted]

Any increase in frequency of tank truck unloading at the above described tank areas that is not consistent with short-term emergency response, seasonal usage, or short-term temporary usage to meet unusual operation demands must be reported to the Department immediately.

If you have questions about this letter, I can be reached at (907) 269-7536.

Sincerely,

Gary Evans

Gary Evans
Environmental Program Specialist

Enclosures:

Enclosure 1: Copy of April 6, 2011 letter (without attachments) from ConocoPhillips Alaska regarding "*Request for Waiver of Secondary Containment Requirements for Selected Kuparuk Tank Truck Loading and Unloading Areas*"

Enclosure 2: Copy of ADEC Guidance No. IPP 2004-01, Revised August 5, 2004, *Secondary Containment Requirements at Tank Truck and Rail Car Loading and Unloading Areas*

Electronic cc:

Scott Pexton, ADEC
Laurie Silfven, ADEC
Tom DeRuyter, ADEC

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February 19, 2009

File Number 305.35
CPAI/KRU

Robyn McGhee
Conoco Phillips Alaska, Inc.
P.O. Box 100360
Anchorage, AK 99510-0360

Subject: **ConocoPhillips Alaska, Inc. (CPAI) Oil Discharge Prevention and Contingency Plan for the Kuparuk River Unit, Plan Number 07-CP-4102. Waiver from the Requirements for Secondary Containment - Tank T-AN105**

Dear Ms. McGhee:

The Alaska Department of Environmental Conservation (Department) has received your November 12, 2008 application for a waiver. This document indicates that the secondary containment around tank T-AN105 is not feasible due to its location inside the module at [redacted] separate level indicating/alarm devices. 18 AAC 75.015 allows the Department to waive a regulatory requirement if the owner or operator demonstrates that an equivalent level of protection will be achieved by using a technology or procedure other than that required by 18 AAC 75.005 – 18AAC 75.085.

Therefore, the Department is waiving the secondary containment requirement for Tank T-AN-105 at CPF2 with the conditions outlined below.

1. CPAI must perform visual inspections on the tank and the module at least once per shift and document the inspections.

2. While the tank is in operation, an employee from CPAI must be present in the module until the use of the tank is complete.

This waiver does not exempt CPAI from the requirements of any other state or federal agencies or municipalities that may apply.

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If you have any questions, please contact Graham Wood at 269-7569 or me at (907) 269-3080.

Sincerely,

Dianne Munson
Acting Section Manager

cc: Betty Schorr, ADEC
Graham Wood, ADEC
Laurie Silfven, ADEC
Ed Meggert, ADEC
Todd Nichols, ADFG
Carol Fries, ADNR
Pam Miller, NAEC
Mac McLean/Jack Winters, ADNR
Carl Lautenberger, EPA
Matt Carr, EPA
Capt. Mark Hamilton, USCG Sector-Anchorage
Gordon Brower, North Slope Borough
Mike Holley, USACE
Christy Bohl, MMS
Response Plans Officer, Nuiqsut
Tom Maunder, AOGCC
Melanie Barber, USDOT
Nina Brudie, ADNR OPMP
Susan Harvey, Harvey Consulting
Legal Director, Trustees for Alaska

STATE OF ALASKA

DEPT. OF ENVIRONMENTAL CONSERVATION
DIVISION OF SPILL PREVENTION AND RESPONSE
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September 13, 2007

File No.: 305.30
(CPAI-Alpine & Kuparuk)

Ms. Leigh McDaniel
ConocoPhillips Alaska, Inc.
P.O. Box 100360
Anchorage, AK 99510-0360

Subject: **ConocoPhillips Alaska, Inc. (CPAI) Oil Discharge Prevention and Contingency Plans for the Kuparuk River Unit and Alpine Development Participating Area. Waiver for Flow Line Marker Requirements**

Dear Ms. McDaniel:

The Alaska Department of Environmental Conservation (ADEC) has reviewed your August 20, 2007 request (revised) for a waiver from the flow line marker requirements in 18 AAC 75.047(e) for CPAI Kuparuk and Alpine facilities. The letter reflects CPAI's revised request as agreed upon in our August 9, 2007 meeting.

Under 18 AAC 75.047(e), line markers must be installed and maintained over each onshore flow line at road crossings and at one-mile intervals along the remainder of the pipe by December 30, 2007. The intent of the regulation is to facilitate rapid shutdown of a leaking line by quickly identifying the line. CPAI is planning to install line markers at all road crossings by December 30, 2007, but is seeking a waiver from the requirement for line markers at one-mile intervals along the cross-country portions of flow lines.

In accordance with 18 AAC 75.015, ADEC may waive a requirement if the owner or operator demonstrates that an equivalent level of protection will be achieved by using a technology or procedure other than that required by 18 AAC 75.005 – 18AAC 75.085.

ADEC approves the waiver request based on the following conditions that provide an equivalent level of protection:

1. CPAI will install additional line markers where flow lines approach drill pads for long spans of remote flow lines by the end of 2007.

2. CPAI pipeline mapping information currently allows rapid identification of flow lines by security, surveillance, and other personnel during routine and emergency operations. CPAI has provided us with a copy of the pipeline mapping data file.

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If you have any question, please contact me at (907) 269-7640.

Sincerely,

Laurie Silfven

Laurie Silfven
Acting Section Manager

cc: Betty Schorr, ADEC
Tanya Verbyla, ADEC
Ed Meggert, ADEC, NART, Fairbanks
Todd Nichols, ADFG, Fairbanks
Jack Winters/Mac McLean, ADNR Habitat, Fairbanks
Carol Fries, ADNR, Anchorage
Carl Lautenberger, USEPA
Capt. Mark DeVries, USCG Sector-Anchorage
Johnny Aiken, North Slope Borough
Melanie Barber, USDOT
Leonard Lampe, Nuiqsut
The Honorable Carl Brower, Mayor of Nuiqsut

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June 22, 2005

File No. 305.35 (CPA-Kuparuk)
File No. 305.35 (CPA NS Exp)

Ms. Leigh McDaniel
Senior Environmental Coordinator
ConocoPhillips Alaska
P. O. Box 196105
Anchorage, AK 99501

Subject: **ConocoPhillips Alaska, Inc. Kuparuk River Unit – Kuparuk and Oliktok Pipelines Oil Discharge Prevention and Contingency Plan and North Slope Exploration Discharge Prevention and Contingency Plan**
Waiver of Oil Storage Tank Construction Requirement/ Approval for Tank Use

Dear Ms. McDaniel:

The Alaska Department of Environmental Conservation (Department) has reviewed your request dated June 9, 2005 for approval of an alternate construction standard for portable, 500-barrel, steel, rectangular "Tiger Tanks" and approval for use of these for oil storage in the Kuparuk River Unit and at your North Slope exploration drilling sites. These tanks, owned by Schlumberger, were constructed by Greer Tank and Welding.

Drawings and supporting documentation for these tanks were previously submitted by ConocoPhillips in a similar request dated December 23, 2004 for the Alpine development facilities. The tank records were determined to not contain sufficient information for the Department to approve the current or future construction standard of these tanks. Therefore, the Department can not issue an approval of this alternate construction standard without additional information.

The tanks have been in service on the North Slope for five years, and have therefore endured the "test of time." It is our understanding that the tanks, while typically used for frac jobs performed with water, will also be used for frac jobs with diesel at Kuparuk and for temporary diesel storage while the topping plant is down. In our opinion, diesel service would not compromise tank integrity since diesel has a lower specific gravity than water (between 0.82 and 0.95, depending on the grade).

In addition, these tanks have undergone hydrostatic testing with the average holding time of 2.5 hrs for 7 tanks and over 8 hrs for 3 tanks. The testing fill heights were 8'11" and 8'10". The average water temperature (during the test) was 78 F.

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Alaska regulations at 18 AAC 75.015 give the Department the authority to waive a regulatory requirement if the owner or operator demonstrates that an equivalent level of protection will be achieved by using a technology or procedure other than that required by 18 AAC 75.005 – 18 AAC 75.090. In a letter dated February 9, 2005, the Department waived the requirement of 18 AAC 75.065(h)(1) for these tanks to be constructed to API 650, API 12, or another standard approved by the Department and approved these tanks for use at Alpine development facilities. Therefore, based on our findings in the February 9, 2005 waiver letter and the expected use of these tanks under similar conditions in similar environments, the Department issues this waiver of 18 AAC 75.065(h)(1), in accordance with 18 AAC 75.015, and approves the use of these tanks at the Kuparuk River Unit and at ConocoPhillips North Slope exploration drill sites for the same service conditions.

This approval applies to the following tanks under the following conditions only:

2SUS18471	2SUS18472	2SUS18473
2SUS18474	2SUS18475	2SUS18476
2SUS18477	2SUS18478	2SUS18479
2SUS18480		

- Fill height of the tanks must be limited to the hydrostatic test fill height.
- The fluid stored in the tanks must have a specific gravity equal to or less than 1.0.
- Hydrostatic testing records must be kept as part of the permanent record of the tanks.
- Since the hydrostatic tests were conducted in a controlled environment, other operational and physical factors must be considered when specifying the operational fill height. The fill height and other operational constraints need to be part of the operating procedures of the tanks.

The Kuparuk and Oliktok Pipelines Oil Discharge Prevention Contingency Plan and North Slope Exploration Oil Discharge Prevention and Contingency Plan must be revised at the next routine update or minor amendment to include this waiver letter.

If you have any questions regarding this review, please contact Wade Gilpin at (907) 269-3060, or me at (907) 269-7680.

Sincerely,

Lydia Miner
Section Manager

cc: Bill Hutmacher, ADEC
Wade Gilpin, ADEC
Gary Evans, ADEC
Sam Saengsudham, ADEC
Ed Meggert, ADEC, Fairbanks
Stephen Geddes/Jeanie Shifflett, CPAI, Anchorage

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March 23, 2005

File 305.35 (CPA/Kuparuk)
File 305.35 (CPA/Alpine)
File 305.35 (CPA/NS Exp)

Mr. Steve Geddes
ConocoPhillips Alaska, Inc.
P.O. Box 100360
Anchorage, AK 99510-0360

SUBJECT: ConocoPhillips (CPA) Kuparuk, Alpine, and North Slope Exploration Oil Discharge Prevention and Contingency Plans; ADEC Plan Numbers 024-CP-4102, 014-CP-4140, 024-CP-5096; Waiver of Secondary Containment Area Capacity Requirements for Doyon Drill Rig 141 Fuel Tank

Dear Mr. Geddes:

The Alaska Department of Environmental Conservation (ADEC) has completed our review of your request dated March 9, 2005 to waive secondary containment area (SCA) capacity requirements for the drill rig fuel tank, number 141-001, which is a permanent fixture of Doyon Rig 141. A waiver of the SCA capacity requirements for this tank was previously issued on April 3, 1998; the waiver applied only to the Kuparuk C-plan and facility. 18 AAC 75.015(a) allows the Department to waive a secondary containment requirement if an equivalent level of protection can be achieved by using a technology or procedure other than that required.

The tank is a [redacted] that is owned and operated by Doyon Drilling, Inc., and is a permanent fixture of Doyon Rig 141. As required by 18 AAC 75.075(a), tanks must be located in an SCA that has the capacity to hold the volume of the largest tank within the containment area, plus enough additional capacity to allow for local precipitation. The double-wall design provides containment for a leak from the inner tank wall. The capacity of the interstitial space is approximately [redacted] The tank is affixed to the roof of the rig, making the installation of additional secondary containment infeasible. (3)

ADEC staff visited the Doyon rig 141 on March 14, 2005. The work required by the April 3, 1998 letter has been completed; the tank's vents are connected to a line that drains to a steel containment structure ("trough") which is located above the fuel fill line (see attached photo). However, in the event of an overfill of the tank, there is a potential that wind could blow the fuel onto the pad or tundra since the bottom of the piping is located well above the wall of the trough. In the event of a spill from the truck fill line, there is a potential for fuel to be released to the pad or tundra. In the current set up of the rig, there is no containment under the truck fill

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or the trough. A temporary lined containment must be placed at this location during fueling operations.

18 AAC 75.075(a) (3) requires that SCAs be checked daily for the presence of oil leaks or spills at a manned facility. It appears that there is no safe method for checking the interstitial space (the SCA) of the tank. However, the overall tank structure can and must be checked daily.

Based on the information provided by CPA and the previous waiver approval, **ADEC is granting this waiver** of the requirements of 18 AAC 75.075(a) for capacity and daily checks for the Doyon Drill Rig 141 fuel tank when it is associated with the Kuparuk, Alpine, or North Slope Exploration facilities. All other requirements of 18 AAC 75.075(a) remain in effect. This waiver supersedes the waiver issued on April 3, 1998 for the Kuparuk plan.

This waiver is subject to the following conditions:

1. A lined containment area must be present under the truck fill line and containment "trough" during tank filling operations. The lined area must extend beyond the ends of the trough and must extend from the footprint of the rig to at least 5 feet beyond the fill line.
2. An operator must be physically present during all fuel transfers, and must visually monitor the tank and associated containment for the duration of the transfer operations.
3. During times when the tank contains product, facility personnel must check the tank for oil spill or leaks at least once per day, weather permitting.
4. The contingency plans must be revised at the next routine update to include this waiver approval letter. The April 3, 1998, waiver in the Kuparuk plan is superseded and must be replaced with this letter.

Please be advised that the approval of this waiver does not relieve you of the responsibility for securing other state, federal or local approvals or permits, and that you are still required to comply with all other applicable laws.

If you have any questions, please contact me at 269-7680.

Sincerely,

Lydia Miner
Section Manager

cc: Bill Hutmacher, ADEC
Gary Evans, ADEC
Laurie Silfven, ADEC
Wade Gilpin, ADEC

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February 13, 2004

File No.: 305.30.4102

Mr. Steve Geddes
ConocoPhillips Alaska, Inc.
P.O. Box 100360
Anchorage, AK 99510-0360

Dear Mr. Geddes:

SUBJECT: ConocoPhillips (CPA) Kuparuk River Unit (KRU) Oil Discharge Prevention and Contingency Plan; ADEC Plan number 024-CP-4102; Waiver of Secondary Containment Area Capacity Requirements for Tanks T1-101, T-2201, T-2202, T-CM01, T-CM02, and T-EF52

The Department of Environmental Conservation (Department) has completed our review of your requests dated July 8 and August 7, 2003 to waive secondary containment area (SCA) capacity requirements for tanks T-CM01 and T-2202. A waiver of the SCA capacity requirements for tanks T-2201, T-CM02, T-EF52 and T1-101 was previously issued on January 30, 1996. 18 AAC 75.015(c) allows the Department to waive a secondary containment requirement if an equivalent level of protection can be achieved by using a technology or procedure other than that required. Our review was augmented by a meeting with KRU Operations staff on July 31, 2003, and our limited internal inspection of tanks T-2201 and T-CM02. We have also reviewed the additional information submitted on August 3 and 7, and November 29, 2003.

As required by 18 AAC 75.075(a), tanks must be located in an SCA that has the capacity to hold the volume of the largest tank within the containment area, plus enough additional capacity to allow for local precipitation. According to the information submitted by CPA, the layout of existing facilities and potential safety hazards prevent the installation of sufficiently sized containment. Also, full-size secondary containment structures would limit the access of fire response equipment to the Central Production Facility (CPF). In some instances, the fire escape routes from the buildings must travel directly over the SCAs creating a potential life-threatening condition in a fire or explosion situation.

The tanks' operating conditions and prevention systems in place are summarized below.

Tank T1-101

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The tank has high liquid level sensors capable of automatically stopping flow to the tank and diverting the liquids to other tanks at the facility. This tank is equipped with internal anodes (cathodic protection) and a thin film liner. Since the tank is elevated, potential leaks from the bottom and sides of the tank can be readily detected. The CPF-2 facility is staffed 24-hours a day and tanks and SCAs are routinely inspected at least once per shift (every 12 hours). According to CPA records, this tank received API 653 internal inspections by API certified inspectors and was found to be in satisfactory condition for continued service on July 21, 1995 and June 16, 2003.

Tanks T-2201, T-2202, TCM01, T-CM02, and T-EF52
All of these tanks are elevated produced water tanks with cone-down bottoms built to API 650 standards. Internal anodes (cathodic protection) and thin film liners are used on all of these tanks. Since these tanks are elevated, potential leaks from the bottom and sides of the tanks can be readily detected. All tanks have multiple high liquid level alarms (three levels of alarm: high, high-high and high-high-high) which will automatically trigger the closure of valves to the production facilities' primary separators which controls fluids going into the produced water tanks. Additionally, a low-level switch in the primary separators closes the line to the produced water tanks to keep oil from entering the tanks. The fluid levels in the tanks are continuously monitored by operators on visual displays at the control panel. The operators follow a standard procedure which requires removal of the accumulated oil layer from the tanks when the oil level reaches a maximum of two feet in depth in order to minimize the volume of oil contained by the tanks. All CPF's are staffed 24 hours a day, 7 days a week, and the SCAs subject to waivers are inspected once per shift (every 12 hours). The five tanks have received API 653 internal inspections as follows:

Tank and Location	Capacity	Last internal inspection
		July 31, 2003
		July 22, 1993
		August 2003
		October 2003
		July 4, 2003

Tank T-2202, additional detail: Tank 2202 was re-coated with WG368 in 1991. This is a high performance modified epoxy coating that has shown excellent performance in KRU fluids (CPF-1 slop oil tank). As noted above, the last internal inspection for T-2202 was performed in July 1993. Nothing more than surface rust was identified in the tank. Minor coating damage (perhaps due to the interior work) was repaired. The cathodic protection system was re-established. Tank T-2202 received a "comprehensive external" inspection in July 2000, when a substantial majority of the cone-bottom, enclosed in a "skirt" that reasonably isolates the tank-bottom from environmental conditions was examined by non-destructive means. The inspection included 4% of the roof, 80% of the tank floor and five 6" diameter locations on the shell. Using this method, no internal corrosion was identified on the shell and floor in the areas scanned, with only minor corrosion on the roof. No external corrosion was identified. Tank T-2202 is scheduled for a comprehensive, internal and external API 653 inspection in the summer of 2005.

Tank T-CM01: This API 650 tank has been in "seawater service" since it was placed into service after construction (1984). It received a "suitability for service" evaluation in 2003 and an API 653 internal inspection in August 2003 so that it could be used as an oil storage tank (produced water) when T-CM02 needs to be taken out of service for inspection and maintenance. The next scheduled internal API 653 inspection is scheduled for August 2013.

Based on the information and justification provided by CPA (and previously by ARCO at the time of the 1996 waiver) and the submittals, meetings, and inspections discussed in the first paragraph of this letter, **the Department is granting this waiver** of the secondary containment capacity requirements of 18 AAC 75.075(a) for the subject tanks. This waiver supercedes the waiver issued on January 30, 1996.

This waiver is subject to the following conditions for all subject tanks:

1. Inspections and records:

a. Routine visual inspections of the subject tanks and secondary containment areas must be conducted by facility operations personnel, at a minimum, every 12 hours, weather permitting. SCAs must be maintained at maximum capacity, i.e., stormwater removal must be performed as needed to minimize the amount of standing-water to a mean accumulation of one inch or less, above and beyond the twice-yearly dewatering specified in Kuparuk's Storm Water Management Plan (SWMP).

b. In accordance with 18 AAC 75.065(k), monthly inspections and annual testing of overfill protection devices, liquid level determination devices, alarms and associated valves must be performed. In addition, an over-fill systems check must be performed by control room operators on a weekly basis.

c. The subject tanks must have API 653 internal inspections every 10 years, unless a shorter interval is prescribed by API 653, in compliance with 18 AAC 75.065(a) and (b), since these tanks will be approximately 30 years old at the next inspection interval and since the secondary containment areas are under-sized.

d. All tests and inspections must be documented in the appropriate logs and tank records. Records must be maintained for the appropriate retention period, as prescribed by current law. Ref: 18 AAC 75.007(h) and 18 AAC 75.065(d).

2. Plan Update: The contingency plan must be revised at the next routine update to include this waiver approval information to ensure this waiver is documented in the plan. The January 30, 1996, waiver is superceded and must be replaced with this letter in Section 2.7 of the approved plan for as long as these tanks are in use with sub-sized SCAs. In addition, the plan must be updated to include the sizes of these and all other SCAs for regulated oil storage tanks covered by the approved plan.

3. Inspection and Maintenance: The required tank inspection schedules, operational procedures and dewatering plan, specified in Condition 1 of this approval, must be included in the "Tank History" files for each tank, as required by 18 AAC 75.065(d). In addition, CPA must take the appropriate steps, such as including the API 653 internal tank inspection requirement in the "SAP" or other prevention/maintenance scheduling system/database, to

ensure that operational staff are prompted to maintain and inspect the tanks and SCAs as specified.

Please be advised that the approval of this waiver does not relieve you of the responsibility for securing other state, federal or local approvals or permits, and that you are still required to comply with all other applicable laws.

If you have any questions, please contact Kirsten Ballard at 269-7541 or me at 269-7680.

Sincerely,

Lydia Miner
Section Manager

cc: Bill Hutmacher, IPP Program Manager, ADEC
Kirsten Ballard, ADEC, IPP, Anchorage
Sam Saengsudham, ADEC, IPP, Anchorage
Sam Means, ADNR
Al Ott, ADNR
Gordon Brower, North Slope Borough
Mike Soblolik/Steve Geddes, ConocoPhillips, Anchorage
Jeff Smith/Leigh Gooding, c/o ConocoPhillips, Anchorage
Brad Frates/Ed Goldman, c/o ConocoPhillips, Anchorage

STATE OF ALASKA

DEPT. OF ENVIRONMENTAL CONSERVATION
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File No: 305.30.4102

November 13, 2003

Mr. Jeff Smith
ConocoPhillips Alaska, Inc.
P.O. Box 100360
Anchorage, Alaska 99510-0360

Dear Mr. Smith

SUBJECT: **Waiver for use of Alternate Materials; Tank T-2201,ConocoPhillips Kuparuk River Unit (KRU). ADEC Plan number: 024-CP-4102.**

The Department of Environmental Conservation (Department) has reviewed your request dated August 4, 2003, and the additional information submitted on August 15, 2003, for a waiver from the requirements of 18 AAC 75.065(a) for two 6" nozzles on Tank T-2201. The Department may waive a requirement of 18 AAC 75.065 if the owner or operator demonstrates that an equivalent level of protection will be achieved by using a technology or procedure other than that required [18 AAC 75.015(c)]. These nozzles were installed in 1997 using "Schedule 40" pipe instead of the required "Schedule 80" pipe. Tank T-2201, an elevated cone-bottom, vertical, steel tank constructed to API Standard 650 in 1981, is used as a produced water tank.

As required by 18 AAC 75.065(a), CPA must maintain tanks in accordance with API Standard 653, Tank Inspection, Repair, Alteration and Reconstruction, First Edition, 1991, and Supplement 1, January 1992, Section 7.7, which specifies that when adding shell penetrations, they must be done in accordance with API 650. API 650 specifies that Schedule 80 pipe be used when the nominal pipe size of shell penetrations are greater than 1.5 inches. Ref: API 650, Ninth edition, July 1993, Addendum 1, December 1994, through Addendum 3, December 1996, Table 3-8—Dimensions for Shell Nozzles.

Based on the information supplied by CPA and our July 31, 2003, on-site inspection of the tank, the Department is granting the waiver for the thinner-walled nozzles. This waiver is subject to the following conditions:

1. CPA must include a provision in their tank inspection program for close inspection of these nozzles during the tank's 5 year external, and 10 year internal, inspections. At a minimum, a complete non-destructive examination of the thicknesses of these nozzles must be performed at each inspection interval and documented in the "tank history" file required by 18 AC 75.065(d).

   This condition is reasonably necessary to ensure the "equivalent level of protection" is maintained. In this case, since the nozzles are thinner than those specified by the standard, specific and detailed testing of the nozzles is required to meet the intentions of 18 AAC 75.065(a).

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2. ConocoPhillips must include a copy of this letter in Section 2.7 of the approved KRU plan for as long as this tank is in use.

   This condition is considered reasonable and necessary to make certain that all the necessary information regarding these specific tank inspection requirements are included in the plan. Ref: 18 AAC 75.425(e)(2)(A).

As CPA continues to upgrade and update your tank inspection program it is our expectation that future nozzles and other tank modifications will meet state regulations. If you have any questions, please contact Kirsten Ballard at 269-7541.

Sincerely,

Lydia Miner
Section Manager

cc: Bill Hutmacher, IPP Program Manager, ADEC
Kirsten Ballard, ADEC, IPP, Anchorage
Sam Saengsudham, ADEC, IPP, Anchorage
Sam Means, ADNR
Al Ott, ADFG
Gordon Brower, North Slope Borough
Steve Geddes, ConocoPhillips, Anchorage
Leigh Gooding, CPA Kuparuk, c/o ConocoPhillips, Anchorage

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DIVISION OF SPILL PREVENTION AND RESPONSE
INDUSTRY PREPAREDNESS PROGRAM
Exploration Production & Refineries

February 26, 2003

File No.: 305.30.4140

Mr. John Whitehead
Alpine Development Project
ConocoPhillips Alaska, Inc.
P. O. Box 196105
Anchorage, AK 99519-6105

Dear Mr. Whitehead:

SUBJECT: **Approval (waiver) of Oil Storage Tank Construction Standards; Oil Discharge Prevention and Contingency Plan ("plan") for ConocoPhillips Alaska, Inc. (CPA) Alpine Development Participating Area; ADEC Plan number: 994-CP-4140**

The Department of Environmental Conservation (Department) has reviewed your January 27, 2003, request for approval for the construction of two types of tanks used for well-work, "Open Top" and "Tiger Tanks,", as "another standard approved by the department" in accordance with 18 AAC 75.065(h)(1). The Department may waive a storage tank requirement of 18 AAC 75.065 if the owner or operator demonstrates that an equivalent level of protection will be achieved by using a technology or procedure other than that required [18 AAC 75.015(c)]. CPA has indicated, and the Department has confirmed, that there are no nationally recognized construction standards for the "Open Top" and "Tiger Tanks." Recognizing that there is no construction standard for these tanks to meet the "new installation" tank requirements of 18 AAC 75.065(h)(1), CPA developed a 'standard' for the construction of these tanks, CPA's standard includes welding procedure specifications, structural integrity calculations, material specifications, and other engineering design considerations to standardize the design, construction and fitness for service of these tanks, based on the intended uses and capacities of the subject tanks.

The specifications have been reviewed by the Department's engineer, Sam Saengsudham, and API 653 Certified Tank Inspector, Kirsten Ballard. Based upon this review, the Department has no objections to or additional comment on the use or design of the tanks as depicted in the BBFM Engineers Inc. design drawings and calculations, submitted on January 31, 2003, with the revised calculations and drawings for the Tiger Tank submitted on February 11, 2003.

Based on the information supplied by CPA and discussions with CPA personnel, the Department is granting the waiver. CPA must include a copy of this waiver in the section of the plan designated as "Compliance Schedule and Waivers," currently Section 2.7, for the duration of the service life of the subject tanks. Facility diagrams and other information required by 18 AAC 75.425(e)(1-3) must also be included.

This waiver, including any necessary changes to the plan, must be incorporated into the plan renewal application currently in process prior to final distribution of the plan, when approved. CPA must notify the Department when any of the tanks are taken out of service or when major repairs are made [Ref: 18 AAC 75.065(e) and 18 AAC 75.415(a)]. This waiver is subject to the following conditions:

1) CPA must use the "Open Top" and "Tiger Tank" designs for any new tanks of these types at CPA's North Slope facilities. Any CPA facility that uses these tanks must include a copy of this waiver in the appropriate section of the applicable plan, for the service life of the tanks included by this waiver. This waiver is transferable to CPA, its subsidiaries and purchasing agents, but not to other plan holders without prior approval.

This condition is reasonably necessary to affirm that these tanks, and any other tanks of this type that are brought into service after May 14, 1992, meet the intent of 18 AAC 75.065(h)(1). The waiver is not transferable without prior approval, as required by 18 AAC 75.400 and 18 AAC 75.415(a).

2) CPA will include the procurement procedures described below whenever new tanks of this type are ordered to ensure new oil storage tanks regulated under 18 AAC 75 are built to the appropriate code. This includes the modification of the "CPA Engineering Standards" for tank design, construction and placement into service to clearly define and identify the new oil storage tank construction requirements of 18 AAC 75.065 for CPA procurement processes. The changes to the CPA Engineering Standards and acceptance protocols will be communicated to CPA Operations/Drilling/Wells management and will be followed when CPA procures new oil storage tanks.

a) The proposed tank design will be developed in compliance with CPA's Tank Design Criteria and Welded Tank Procurement Specification or Fiberglass Reinforced Tank Specification, depending on whether the tank is of welded or fiberglass construction;

b) If a tank design code is desired that is not explicitly allowed by 18 AAC 75.065, a request for a waiver will be submitted to the Department for approval prior to the commencement of any construction work;

c) The new tank cannot be released for service until the Corrosion Department has completed a "Pre-Operational Tank Inspection Checklist" and all outstanding items have been resolved. This will ensure that the new tank has all the appropriate documentation and complies with 18 AAC 75.065 before it is put into service;

d) A record for the tank will be created in the Corrosion Department's "Tank Database," where future external and internal inspection dates will be assigned and entered. In addition, all records of inspection results and corrective actions will be kept for the service life of a tank, as required by 18 AAC 75.065(d);

e) The new tank information will be added to the applicable plan, currently Table 2-6;

f) The requirements of 18 AAC 75, as well as the above CPA procedural requirements, have been communicated to, and will continue to be followed by, the Wells, Drilling, Operations, Projects, Engineering and Procurement Organizations, or their equivalents should CPA reorganize, sell or otherwise re-name the organizations that make up CPA.

g) This waiver shall be binding to CPA, its agents, successors, and assigns and upon all persons, contractors and consultants acting on behalf of CPA.

This condition is reasonably necessary considering that CPA is a large company with numerous employees, contractors, subcontractors, agents and potential successors, who may purchase oil storage tanks for use in the State of Alaska at the Kuparuk or Alpine facilities. Incorporating the requirements for new oil storage tanks into CPA's internal procurement process, including provisions for the sale of the company or its assets, is the best way to ensure that a new Tiger or Open Top tank that is ordered or placed into service after May 14, 1992, will meet the requirements of 18 AAC 75.065(h and j), that the information regarding a tank is maintained to meet the requirements of 18 AAC 75.065(d), and the information is maintained in the plan as required by 18 AAC 75.425(e)(2)(A).

3) These tanks are subject to all other applicable requirements of 18 AAC 75.065 and 18 AAC 75.075 for tank inspection, maintenance, and secondary containment requirements.

As required by 18 AAC 75.065(h)(1), this condition is reasonably necessary to insure that any new oil storage tanks needed for operations at CPA facilities on the North Slope will be submitted for approval prior to purchase, including "Open Top Tanks" and "Tiger Tanks" without the need for additional approvals for these two tank designs.

Please be advised that the approval of this waiver does not relieve you of the responsibility for securing other state, federal or local approvals or permits, and that you are still required to comply with all other applicable laws.

If you have any questions, please contact Kirsten Ballard at 269-7541.

Sincerely,

//S//
Lydia Miner
Section Manager

cc: Kirsten Ballard, ADEC
Sam Saengsudham, ADEC
Sam Means, ADNR
Al Ott, ADFG
S. Adams, North Slope Borough
Brad Frates, CPA
Randy Kanady/Shellie Colegrove, CPA
Bob Hale/Steve Geddes, CPA
Michael Erwin, Supervisor, WNS Operations, CPA

STATE OF ALASKA

DEPT. OF ENVIRONMENTAL CONSERVATION
DIVISION OF SPILL PREVENTION AND RESPONSE
INDUSTRY PREPAREDNESS AND PIPELINE PROGRAM
Exploration Production & Refineries

TONY KNOWLES, GOVERNOR
555 Cordova Street
Anchorage, AK 99501
PHONE: (907) 269-3094
FAX: (907) 269-7687
http://www.state.ak.us/dec

October 2, 2002

File No: 305.30.4102

Mr. Tom Wellman
ConocoPhillips Alaska, Inc.
P.O. Box 100360
Anchorage, AK 99510-0360

Dear Mr. Wellman:

SUBJECT: **Approval of Amendment for Alternate Tank Construction Standard** UL-142 Tank at DS-2N, as needed for the approved Oil Discharge Prevention and Contingency Plan ("plan") for ConocoPhillips Kuparuk River Unit (KRU). ADEC Plan number: 994-CP-4102.

The Department of Environmental Conservation (Department) has reviewed the request dated August 26, 2002, for approval of an alternate oil storage tank construction standard, as required by 18 AAC 75.065(h)(1), for "new installations" (18 AAC 75.990(68)). ConocoPhillips has indicated that Tank #T-2N01, a horizontal, steel tank constructed in December of 2001 was built to UL-142 standards. UL-142 standard tanks are internationally recognized as an acceptable standard for the construction of horizontal, welded steel tanks. In addition, ConocoPhillips has placed this tank in a secondary containment area, as required by 18 AAC 75.075. The Department has no objection to the use of this tank since it was built to an acceptable, recognized industry standard.

Based on the information supplied by ConocoPhillips and the Department's September 25, 2002, on-site inspection of the tank, the Department has determined that the use of this tank will not diminish ConocoPhillips' ability to respond to a discharge. In addition, the use of this tank will not increase or present an unacceptable risk of an oil discharge. Therefore, in accordance with 18 AAC 75.415(d), the Department approves the referenced amendment to the plan. The February 18, 2000, August 9, 2000, January 22, 2001, February 16, 2001, and June 20, 2001, amendments and the November 15, 1999, approval of the referenced plan remain in effect, as amended by this approval.

In addition to all the terms and conditions of the above referenced approval and amendment letters, this amendment approval is subject to the following conditions:

1. By October 21, 2002, ConocoPhillips must provide a new "Management Approval Letter" for the KRU plan, as required by 18 AAC 75.425(c)(3).

2. By October 21, 2002, ConocoPhillips must provide to the Department and other parties in possession of the plan, the diagrams and other information required by 18 AAC 75.425(e)(1-3) to include the amended information into the plan. This includes revising Table 2-6 of the current approved plan to include the same tank information as other tanks at KRU.

3. ConocoPhillips must include a copy of this letter in Section 2.7 of the approved KRU plan for as long as this tank is in use. This condition is considered reasonable and necessary to make certain that all the necessary information regarding the tank construction standard is included in the plan.

Please be advised that the approval of this amendment does not relieve you of the responsibility for securing other state, federal or local approvals or permits, and that you are still required to comply with all other applicable laws, especially in regard to the in-place abandonment of the empty diesel line.

ADJUDICATORY HEARING: Any person who disagrees with this decision may request an adjudicatory hearing by serving upon the Commissioner a request for hearing that complies with the requirements of 18 AAC 15.200-310. Hearing requests must be delivered to the Commissioner of the Department of Environmental Conservation at 410 Willoughby Ave, Suite 105, Juneau, AK 99801-1795 within 30 days of receipt of this letter. If a hearing is not requested within 30 days, the right to a hearing is waived and the decision becomes final. Please send a copy of the hearing request to the undersigned.

Thank you for coordinating this plan amendment with the Department. If you have any questions, please contact Kirsten Ballard at 269-7541.

Sincerely,

Lydia Miner
Section Manager
Exploration Production and Refineries Section

cc: Bill Hutmacher, IPP Program Manager, ADEC
Kirsten Ballard, ADEC
Sam Means, ADNR
Al Ott, ADFG
Gordon Brower, North Slope Borough
Steve Geddes, ConocoPhillips

ARCO Alaska, Inc.
Post Office Box 100360
Anchorage, Alaska 99510-0360
Telephone 907 276 1215

xc: Tomkiellman
Brockett/Dash
Gray/Servin

April 18, 1999

Mr. Robert Watkins
Alaska Department of Environmental Conservation
Division of Spill Prevention and Response
Industry Preparedness and Pipeline Program
555 Cordova Street
Anchorage, AK 99501

Re: ARCO Alaska, Inc. (AAI) - Below Grade Piping (BGP) Corrosion Control Program

Dear Mr. Watkins:

On February 23rd, 1999, AAI and ADEC representatives met in Anchorage to review the results of AAI's 1998 Below Grade Piping (BGP) activities, and to exchange information concerning available technologies for performing corrosion surveys. The meeting was the result of a prior commitment made by AAI to share new technical information, and to review the results of AAI's 1998 field survey and inspection program for below grade piping. At the conclusion of the meeting, ADEC requested a description of AAI's proposed 1999 BGP program activities, as well as a written notification that AAI's BGP programs are documented in the current Oil Spill Prevention and Contingency Plans (C-Plan) for both Prudhoe Bay EOA and Kuparuk.

As discussed in the meeting, the proposed activities for 1999 are primarily a continuation of those performed in 1998. Visual inspections will be repeated throughout both fields and corrective action will be performed and documented in those areas requiring work, such as at blocked or partially blocked pipe casings. Approximately 200 cased road crossings in Prudhoe and 100 in Kuparuk will be prioritized and inspected using the various technologies described at our meeting. In addition, inspections will be performed on piping within utilidors which were not completed during 1998. A more detailed list of AAI's proposed 1999 BGP activities is attached.

Because the BGP plans are susceptible to frequent change, AAI and ADEC have agreed not to include them as attachments to the AAI C-Plans. However, reference to ADEC's October 26, 1998 approval of the BGP plan will remain in the approved EOA/GPMA C-Plan (Section 2.1.8). For consistency, a similar reference will be included in the upcoming revision of the Kuparuk C-Plan.

04/18/99
Robert Watkins

If you have questions concerning the attached 1999 BGP program, please call the AAI Corrosion Supervisors at (907) 659-5050. Other questions can be directed to us at (907) 659-5999.

Sincerely,

Robert Lipchak/Caryn Rea
Senior Compliance Coordinator
Field Environmental Compliance

Attachment

cc: J. Sautner, ADEC IPPP
T. Moore, ADEC IPPP

STATE OF ALASKA

READ

TONY KNOWLES, GOVERNOR

Telephone: (907) 269-3094
Facsimile: (907) 269-7687
TTY: (907) 269-7511

DEPT. OF ENVIRONMENTAL CONSERVATION
DIVISION OF SPILL PREVENTION AND RESPONSE
Industry Preparedness and Pipeline Program
Exploration, Production and Refineries Section
555 Cordova Street
Anchorage, AK 99501

cc: Braux / Hill
Dahlquist / Brockett

October 26, 1998

Mr. Bill Johnson
ARCO Alaska, Inc.
Prudhoe Bay Field Manager
P.O. Box 100360
Anchorage, Alaska 99510- 0360

File No.: 305.20

Dear Mr. Johnson:

Subject: Corrosion Control Program for Buried and Below Grade Piping; ARCO Prudhoe Bay Unit

Thank you for your letter of September 29, 1998 summarizing our June 2, 1998 meeting regarding ARCO's program for corrosion control for buried and below grade piping at your north slope facilities. As noted in your letter, the Department gave verbal approval at the June 2 meeting for ARCO to proceed with the program for the 1998 season.

As a follow-up to your September 29 letter, this is to inform you that the Department approves your corrosion control program as presented in your January 29, 1998 submittal and further clarified in our June 2, 1998 meeting. We also concur with the additional clarification presented in your most recent letter on the specifics of your visual surveys.

As noted in your letter, the Department is anticipating an annual report summarizing your 1998 program and findings by December 31, 1998. After reviewing this information it was agreed that we will meet again to further discuss the success of the program and what, if any, revisions may be necessary prior to final approval of a long-term program to be incorporated into the contingency plan. Your letter states that this follow-up meeting will occur as part of a technology workshop sometime in the first quarter of 1999.

We look forward to working with you to finalize your corrosion control program. The Department appreciates ARCO's efforts to improve spill prevention at your North Slope facilities. If you have any other questions, or if I can be of any assistance, please contact me (907) 269-7539 or Robert Watkins (907) 269-7680 at this office.

Sincerely,

Joe Sautner
Manager

RW/JS/pea: (G:\EQ-CLER\JOES\ARCO-COR.DOC)

cc: Chris Brown, ARCO, Kuparuk
Bruce St. Pierre, ARCO, Kuparuk
Bruce McKenzie, Alyeska Pipeline
Robert M. Lipchak ARCO
Scott Glaser, ARCO
Caryn L. Rea, ARCO
Robert Watkins, ADEC
Ted Moore, ADEC

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PART 3 SUPPLEMENTAL INFORMATION [18 AAC 75.425(e)(3)]

3.1 FACILITY DESCRIPTION AND OPERATIONAL OVERVIEW [18 AAC 75.425(e)(3)(A)]

The Kuparuk Field and its satellite fields (Meltwater, Tabasco, Tarn, and West Sak) are located 30 miles west of Prudhoe Bay on the North Slope of Alaska. The field covers approximately 500 square miles (see Appendix A, Figure A-1). The Kuparuk Field and satellite fields are owned by the Kuparuk River Unit (KRU) working interest owners and operated by CPAI. The ownership is as follows:

Kuparuk

- ConocoPhillips 55.3%
- BP 39.2%
- Chevron 4.9%
- ExxonMobil 0.6%

Kuparuk Satellites

- ConocoPhillips 52.2% - 55.5%
- BP 37.0% - 39.3%
- Chevron 4.9%
- ExxonMobil 0.2% - 5.8%

The Kuparuk Crude Oil Transmission Pipeline (Kuparuk Pipeline) system is approximately 37 miles long and runs between the Kuparuk Field Central Processing Facility (CPF) CPF-2 and Alyeska Pipeline Service Company (Alyeska) operated Pump Station 1 of the Trans Alaska Pipeline System (TAPS). The Oliktok Fuel Gas Pipeline is approximately 28 miles long and runs between CPF-1 at Kuparuk and Prudhoe Bay Unit (PBU) Skid 50 near Pump Station 1. The Oliktok Pipeline was converted from natural gas liquid to fuel gas service in 2014. Kuparuk Pipeline and Oliktok Fuel Gas Pipeline are owned by Kuparuk Transportation Company and Oliktok Pipeline Company, respectively, and CPAI operates both.

The major facilities at the Kuparuk Field are illustrated in figures presented in Appendix A and mainly consist of:

- Drill sites (DS): 47 drill sites, with approximately 556 producing wells and 428 injection wells;
- Three CPFs;
- Flowlines between the drill sites and the three CPFs;
- Seawater Treatment Plant (STP), with a maximum capacity of _____ day (bpd); and
- Associated support infrastructure.

The Kuparuk Pipeline system consists of:

- Approximately 9 miles of pipe from CPF-2 to CPF-1;
- Approximately 28 miles of pipe from CPF-1 to TAPS Pump Station 1;

The latitude and longitude for all CPAI North Slope facilities are shown in the Alaska Clean Seas (ACS) *Technical Manual,* Volume 2, Map Atlas.

3.1.1 Facility Storage Containers [18 AAC 75.425(e)(3)(A)(i) and (ii)]

A summary of the major features of the regulated oil storage tanks at Kuparuk are provided in oil storage tank tables provided in Appendix B.

Details regarding secondary containment for tanks are provided in Section 2.1.9. Storage tank locations and containment sites are shown on the facility diagrams in Appendix A.

3.1.2 Transfer Procedures and Major Fueling Areas [18 AAC 75.425(e)(3)(A)(vi)]

Fuel or Chemical Transfer Operations

Fuel transfer procedures have been developed and implemented for North Slope operations. The North Slope Fluid Transfer Guidelines in the *North Slope Environmental Field Handbook* and the Flammable and Combustible Fluid Transfer Standard in the *Alaska Safety Handbook* describe practices for safe, responsible transfer of flammable and combustible fluids. Current guidelines are available on the CPAI intranet, including standard operating procedure for fuel transfers and proper use of surface liners and drip pans.

Employees must follow established CPAI safety procedures for conducting fuel and chemical transfers. Procedures require continuous monitoring during fluid transfers and that employees position ignition sources away from the transfer operation, establish emergency exit paths and fire lanes at the site, establish the flash point and temperature of the fluid transferred, follow specific bonding and grounding procedures, and have adequate fire suppression equipment available. Dry-lock fittings will be used on fuel or chemical transfers greater than 4,500 gallons. Besides storage/staging of equipment, fuel and chemical transfers are not conducted within 100 feet of surface water, where practical.

Before transfers begin, tank and container levels are checked to prevent overfilling. Absorbents or catch basins are placed under connections and vents to contain potential leaks or drips.

The operator closely monitors all transfers throughout the entire operation, maintaining a constant line-of-sight to the transfer. Transfer operations are not left unattended. For transfers requiring two persons, the equipment operator and observer maintain constant communication by voice, radio, or hand signals. Tank levels, containment, absorbents, and piping are inspected after each transfer for signs of fuel or chemical loss, leakage, or failure.

Transfer from Fueling Truck to Equipment

Fuel transfer operations are conducted with the fueling truck operator in constant attendance. All fuel hose transfer connections use a drip pan or other containment (e.g., built-in). The fueling truck also carries absorbents, waste containers, and tools to contain and clean up minor drips and spills.

3.1.3 Pipelines and Facilities [18 AAC 425(e)(3)(A)(vii)

Oil Pipelines

Flowlines

Flowlines connect the drill sites to CPF-1, CPF-2, and CPF-3. The flowlines include the two-phase production and test flowlines, gas lift lines, water injection lines, and gas injection lines. Flowlines are constructed to American Society of Mechanical Engineers (ASME) standards B31.4 or B31.8. The insulated lines are generally located on vertical support members (VSMs) adjacent to the field roads between the drill sites and CPFs.

Each flowline has manual valves at both ends to mitigate backflow from other drill sites in the event of a catastrophic flowline failure. Detection of any flowline leak would result in an immediate response with appropriate action taken to minimize the release. All flowlines are visually inspected on a daily basis by ground vehicle, weather and snow conditions permitting.

Facility Piping

Facility piping connects the wellhead to the flowline. Facility piping is constructed to ASME B31.3, B31.4, or B31.8.

All producing wells are equipped with surface safety valves. Some wells have subsurface safety valves. These valves will close automatically if the wellhead pressure falls outside a specified range. However, if a small leak develops in the well line and the pressure loss is not sufficient to fall below this range, the automatic valves may not react and visual detection of the leak would be required.

Kuparuk Crude Oil Transmission Pipeline

The Kuparuk Pipeline right-of-way passes through a corridor approximately 37 miles long. The Kuparuk Pipeline carries sales-quality crude oil from Alpine, Milne Point, Nikaitchuq, CPF-2, and CPF-1 to Pump Station 1. The pipeline design basis is summarized in Table 3-1.

Approximately 9 miles are comprised of 18-inch-diameter pipeline connecting CPF-2 and Alpine to a connection manifold located next to CPF-1. At CPF-1, processed sales quality crude oil from Alpine, Nikaitchuq, and CPF-2 are combined for shipment in the 24-inch pipe to TAPS Pump Station 1, with Milne Point sales oil entering the Kuparuk Pipeline approximately 6 miles downstream of CPF-1. The Kuparuk Pipeline has a blinded 6-inch connection approximately 0.5 mile downstream from the connection manifold.

Both the 24-inch and 18-inch lines connecting the manifold at CPF-1 and the TAPS tie-in locations are insulated by a 2.5-inch-thick coating of polyurethane foam. Each pipeline is wrapped entirely in a steel jacket for weatherproofing and prevention of insulation degradation and external pipeline corrosion. Insulation and steel jacketing may be removed from selected locations during weld and external corrosion inspections.

Custody of the oil is transferred from CPAI to Kuparuk Transportation Company at the oil shipping meters at CPF-1 and CPF-2. Custody is then transferred to Alyeska at TAPS Pump Station 1 for the oil line. Although custody of the oil changes, CPAI assumes responsibility for response to spills from the Kuparuk

Pipeline, or associated facilities. Once the oil reaches Pump Station 1, Alyeska assumes responsibility for any spills from their facilities or TAPS.

The pipeline is supported entirely on steel VSMs that maintain the level of the pipeline approximately 5 feet above the ground. The VSMs prevent the pipeline from snow cover, protects the permafrost, and provides for animal crossings.

TABLE 3-1:
PIPELINE DESIGN BASIS

LINE	OUTSIDE DIAMETER (inches)	ANSI CLASS	BLOCK VALVE LOCATION	LENGTH (feet)	MAXIMUM ALLOWABLE OPERATING PRESSURE (psig)
					1,415
					1,415

[1] Valves have electric-powered actuators, which can be initiated from the CPF-3 control room.

The Kuparuk Pipeline has a throughput capability of 429,000 bpd, with a current throughput of approximately 280,000 bpd (based on the average of throughput rates from 2007 to 2011). In late 1986, another injection point was added approximately 6 miles downstream from the connection manifold for crude oil transportation from the Milne Point Unit. The source normally adds approximately 30,000 bpd. In early 2011, an injection point was added for crude oil transport from ENI's Nikaitchuq Unit, which at peak production, is estimated to add approximately 28,000 bpd.

Maximum operating pressure for the Kuparuk Pipeline is 1,415 psig at 150 degrees Fahrenheit (°F). This has been established in accordance with the pressure rating allowable for the pipeline's 600# American National Standards Institute (ANSI) flanges, as determined by ASME Code B16.5.

There are eight shipping pumps: four each at CPF-1 and CPF-2. Crude oil measurement at CPF-1 is accomplished through four 4-inch meters. Crude oil at CPF-2 is metered through two of three 6-inch meters available. A metering skid is located at TAPS Pump Station 1 to facilitate leak detection by allowing volume comparison between oil discharged from the facilities and oil received at TAPS Pump Station 1.

The oil pipeline is fitted with a launcher at the connection manifold and a receiver near TAPS Pump Station 1 for a pigging system.

Facilities

Central Production Facilities

Each CPF has one oil separation train and one gas processing train. The product oil is delivered to Pump Station 1 via the Kuparuk Pipeline, meeting TAPS specifications. The processed gas from these facilities is used for fuel gas and for gas lift at the drill sites, with the remainder re-injected or used as miscible injection (MI).

CPF-3 is a partial crude oil production facility with a maximum liquid (oil and water combined) output of 155,000 bpd and associated gas of 150 million standard cubic feet per day. CPF-3 does not fully process the crude oil to pipeline specification. The wet, unstabilized crude oil is pumped to CPF-1 and/or CPF-2, where it is combined with crude oil from those facilities for final processing. The design of CPF-3 differs from that of CPF-1 and CPF-2, although there are similarities in design philosophies and concepts.

Produced fluids from the drill sites flow into CPF-1, CPF-2, and CPF-3, where they are separated into crude oil, produced water, and produced gas in the primary separator. The wet crude oil from the CPF-3 primary separator flows to booster and transfer pumps and is transported by pipeline to CPF-1 and/or CPF-2, where it joins with their respective partially processed wet crude oil streams for final separation and processing.

The produced gas from all CPFs separated from the crude oil and produced water is compressed in three stages and dehydrated using a triethylene glycol dehydration system. To improve liquid hydrocarbon recovery and prevent hydrocarbon condensation, the hydrocarbon dew point of the gas is reduced to 40°F. This processing is required to prevent hydrate formation during further processing and usage of the produced gas.

The produced gas has three main uses: fuel, artificial lift, and reservoir recovery management. The portion of the produced gas used as fuel gas is burned in utility furnaces and gas-fired turbines, and in the flare as purge gas. The fuel gas system, due mainly to gas turbine requirements, operates at approximately 200 psig. The portion of the produced gas used as lift gas is injected into the outside annulus of the crude oil production wells and released near the bottom of the well to help lift the crude out of the well and increase the crude oil production rate.

Gas is further compressed to approximately 4,000 pounds per square inch (psi) by injection compressors at CPF-1 and CPF-2 for re-injection into the reservoir either as gas only or blended with NGL to form MI. CPF-3 does not have gas injection compressors. Produced water is also recovered and re-injected into the reservoir at all three facilities at approximately 3,000 psi.

Oil Handling System

Kuparuk crude oil fluids are routed from wellhead to the CPFs through pipelines which may accommodate production at one or more drill sites. Processing occurs at each CPF. Sales oil is metered and shipped to TAPS only from CPF-1 and CPF-2. CPF-3 produces degassed "wet oil," which it pumps to the other plants for final processing. The wet oil flow split between CPF-1 and CPF-2 can be varied from 0 to 100 percent.

Oil Processing

The reservoir fluid is delivered to the CPFs through several common flowlines and/or test lines and combined in an inlet manifold module. At CPF-1, production from the test lines is manifolded to the test separation header and to the production header in the inlet manifold module.

The combined production header flow enters the primary separator, which separates the oil, gas, and water, with the water going to the produced water facilities and the gas going to the gas processing train. At CPF-1 and CPF-2, the oil stream flows to the secondary separator for additional separation, with separated gas and water routed the same as from the primary separator.

The oil stream, with some residual entrained gas and water, flows through a shell and tube crude heater, then to the electrostatic coalescer. In the electrostatic coalescer, a combination of heat, residence time, and electrical coalescing removes the remaining water from the oil. The water goes to the produced water facilities and the oil goes to the crude surge drum after it passes through the crude cooler. Product oil is further cooled as required, metered, and pumped through the oil gathering system to TAPS Pump Station 1.

Gas Handling System

Dissolved and free gas in the crude fluids is routed from wellhead to CPF through pipelines that may accommodate production at one or more drill sites. At all three CPFs, the gas is separated, dehydrated, scrubbed of NGLs, and compressed. Gas is used as fuel or sent back to wellheads for artificial lift. Gas remaining is collected and compressed at CPF-1 and CPF-2 for injection as lean gas or MI. MI is a mixture of produced gas blended with NGLs at CPF-1 and CPF-2.

The gas streams are processed by three banks of gas-lift compressors and three banks of gas injection compressors. Gas, separated at the three processing facilities, is compressed by the gas-lift compressors and distributed to a common tie line. The common tie-line supplies gas to gas-lifted wells in the field, fuel gas for drill site heaters, the STP, Kuparuk Industrial Center (KIC), the Frame 5 and 6 (Power Generation), and the NGL Plant.

All three CPFs currently process more gas than is consumed by fuel and other losses. A gas management program was implemented to handle the excess formation gas. This program currently compresses gas from the tie-line with the injection compressors at CPF-1 and CPF-2 and injects it into miscible water alternating gas (MWAG) wells throughout the field. The gas volume compressed by the gas injection compressors is equal to the amount of formation gas produced by flowing and gas-lifted wells minus fuel and shrinkage, and is thus essentially recycled.

Seawater/Produced Water Handling System

Entrained and free produced water in crude fluids is routed from wellheads to CPFs through pipelines that may accommodate production at one or more drill sites. Produced water is then separated and injected for reservoir pressure support and hydrocarbon displacement. Some produced water at CPF-3 remains commingled with its crude and is transferred through the wet oil line to CPF-1 and CPF-2.

Seawater is taken from the Arctic Ocean, processed at the STP, and is delivered at low pressure to all three CPFs where booster and injection pumps raise the pressure to approximately 3,000 psi for waterflood injection.

Each CPF independently manages produced water and seawater injection systems to optimize waterflood performance within facility constraints while mitigating the known corrosion effects caused by mixing the two water sources.

Miscible Injectant Handling System

NGLs are collected from various locations along the gas handling trains at CPF-1 and CPF-2. They are pumped to injection pressures and mixed with lean injection gas to create MI, a compositional-specific fluid for enhanced oil recovery (EOR).

Closed Hydrocarbon Drain and Slop Oil Facility Systems

Module surface drains flow to module sumps, which are then pumped to a central storage drum. Process equipment can be drained to closed hydrocarbon drains (CHDs). The CHDs connect to the CHD flash drum where vapors are flashed off the liquid. Fluids from the module surface drains sump drum and the CHD flash drum, and hydrocarbons skimmed from the produced water tank, are pumped to the slop oil tank. These fluids are then pumped back into the process system for oil recovery. All process vessels are gas blanketed.

Diesel Production and Sales

Diesel is produced at the Kuparuk Unit Topping Plant (KUTP) at CPF-1 for use within Kuparuk and for third-party sales. Bulk shipments from the KUTP for use in the field may be dyed for spill tracking.

Drill Site Production and Injection Facilities

Produced fluid flows through a production well line from the individual well to the manifold building. Inside the manifold building, normal flow is through a choke, and then through the production header and heater. Each well can be manually diverted to the test header. The fluid then flows through the test header and heater and into the test separator. Oil, water, and gas are separated, measured, recombined, and returned to the main production line downstream of the production heater. All well fluids leave the drill site in a single flowline and go to a CPF.

Lift gas is supplied to the drill sites. The incoming lift-gas line enters the manifold building, ties into the lift-gas header, and is distributed to the wells through individual lift-gas well lines equipped with flow measurement, gas lift chokes, isolation valves, and check valves.

Water injection fluid flows through an injection header or trunk line where it is distributed to individual injection wells via well lines equipped with flow measurement, injection chokes, isolation valves, and check valves. Many injection wells are also equipped with independently metered lean gas or MI gas, which can be alternated with water injection for improved reserves recovery.

The manifold building houses header (production, test, lift gas, water injection, and methanol or diesel drain bypass) manifolds, a test separator, an electrical/instrumentation area, and a pig receiver/launcher.

corrosion, inhibit scale formation, and assist in fluid separation. Most drill sites also have bulk storage of methanol or diesel, which is used for well work and/or freeze protection of surface piping and wellbores through the permafrost region. Some locations are equipped with diesel-driven pumps to displace freeze protection fluids out the well lines and down the wellbores. However, in most locations, a service company is called to perform these operations with mobile equipment.

Seawater Treatment Plant

The Kuparuk STP, located at Oliktok Point, is an integral part of CPAI's full-field waterflood of the Kuparuk oil field. The facility was designed to process in excess of 623,000 bpd of seawater. The seawater product is used for injection to maintain producing reservoir pressure and extend the useful life and yield of the field.

The STP is a self-contained process plant that treats seawater drawn from the Beaufort Sea. Seawater treatment at this facility consists of clarifying (during summer season), straining, heating, filtering, biotreating, and de-aerating. The plant produces water of sufficient quality for injection into the oil field.

The Kuparuk STP's clarifier system reduces summer intake seawater solids to a level within seawater filter design limitations. The system's reactor clarifier is a solids contacting unit for mixing, solids flocculation, solids recirculation, and sludge concentration and removal within a single tank. The general operating principle for the reactor clarifier is the enhanced formation of floc (or agglomerated solids), which is sufficiently large to settle by gravity within the unit. The formation of floc is accomplished through mixing raw water and suspended solids with treatment chemicals and contacting with previously formed solids. A sludge (settled floc) concentrating mechanism also provides a means for internal recirculation of solids critical for contacting with raw feed solids.

Straining and filtering operations remove suspended solids down to 1 part per million (ppm). This minimizes the possibility of blockage of pore passages in the reservoir rock and the eventual restriction of injection into the well. Solids removal is also a critical requirement for mitigating corrosion in the surface water distribution piping.

Biotreating, to avoid biofouling of process equipment and to mitigate corrosion in the surface water distribution piping, is performed by the addition of sodium hypochlorite and/or a chemical biocide called glutaraldehyde. Biotreating also neutralizes sulfate-reducing bacteria, which, if allowed to enter the oil-producing formation, feed on sulfur compounds and produce hydrogen sulfide (H_2S) gas.

The STP heats seawater from the Beaufort Sea to 60°F. In winter, the water enters the STP at 28°F to 32°F, while in summer the temperature may be as high as 50°F. The heating process serves several functions: it reduces fluid viscosity to allow for better filtration, helps dissolved-oxygen stripping in the de-aeration process, and prevents freeze-up of the seawater during transfer to the CPFs.

De-aeration or deoxygenation of the seawater is one of the most important functions of the STP because oxygen is the most corrosive agent to carbon steel. Oxygen concentration can be as high as 15 ppm by weight in the winter months. De-aeration removes dissolved oxygen to less than 20 parts per billion by weight by using fuel gas as the stripping medium.

Gravel Pads

Kuparuk facilities are constructed on approximately 50 gravel pads throughout the field. The pads are approximately 5 feet above the surrounding tundra elevations. Most of the gravel pads are graded nearly flat to minimize surface drainage onto the tundra. In addition, the gravel pads are frozen for eight months of each year; thus, they are essentially impermeable during that time. Spills are cleaned up immediately, and any contaminated gravel is removed and disposed of in an approved manner.

Reservoir Description

The Kuparuk field consists of multiple reservoirs including the Kuparuk, West Sak, Tarn, Meltwater, Ugnu, and Tabasco oil pools. These reservoirs are developed and produced with Kuparuk infrastructure.

The Kuparuk reservoir lies within the oil-bearing intervals of the Kuparuk River Formation, a sequence of shallow marine clastic sediments that was formed in the lower Cretaceous age, near the end of the Mesozoic era. The formation was deposited in a marine environment and is composed of thin layers of sandstone (less than 50 feet thick in most places) spread over a wider area. The Kuparuk River Formation is divided into upper and lower members, with approximately 60 percent of the reserves in the upper member.

The Kuparuk oil pool lies approximately 5,600 to 6,500 feet subsea. Average production from a single Kuparuk well varies but typically ranges from 500 to 1,000 barrels of oil per day (bopd). Oil production from the Kuparuk reservoir is approximately 95,000 bopd. Satellite fields (West Sak, Tabasco, Tarn, and Meltwater) contribute an additional 32,000 bopd.

The West Sak reservoir overlies the Kuparuk River Formation. West Sak is a shallow reservoir that lies roughly 3,000 to 4,500 feet subsea, and beneath about 1,800 feet of permafrost. West Sak is a viscous or heavy oil found within a poorly consolidated, sandy interval. The sand and proximity to permafrost, which lowers its temperature, makes it challenging to produce. The oil is characterized by varying degrees of biodegradation, with American Petroleum Institute (API) gravities from 10 to 22 degrees.

The Tarn reservoir lies stratigraphically between the Kuparuk River Formation and the West Sak sands. The top Tarn reservoir is located between 4,900 and 5,500 feet subsea, with an oil gravity of 37 degrees API.

The Meltwater reservoir exists stratigraphically between the Kuparuk River Formation and West Sak sands and is a stratigraphic equivalent to Tarn. The top Meltwater reservoir is located between 4,900 and 5,500 feet subsea, with an oil gravity of 37 degrees API.

The Ugnu Formation overlies the West Sak sands in the KRU. The oil is more biodegraded than the West Sak reservoir oil and has API gravities ranging from 6 to 12 degrees. The top of the Ugnu sands range in depth from 1,000 feet subsea in the west to 3,900 feet subsea in the east.

The Tabasco Formation lies beneath the West Sak sands within the KRU. Measured oil gravities range from 15 to 17 degrees API. The top ranges in depths from 2,900 to 3,300 feet subsea.

The Kuparuk Field started up in late 1981 with solution gas as the primary drive mechanism. In 1982, gas lift was started and gas injection into the C sand gas storage area at CPF-1 began. Incremental waterflood was implemented in 1983 and full-field waterflood started in 1985. Water alternating gas began in 1986 and EOR, with a miscible hydrocarbon solvent, was implemented on a pilot scale in 1988. A large-scale EOR project was implemented in 1995.

3.2 RECEIVING ENVIRONMENT [18 AAC 75.425(e)(3)(B)]

The Kuparuk development area is located on the Arctic Coastal Plain and covers an expanse approximately 25 miles by 18 miles. The terrestrial system in the vicinity of the Kuparuk Field includes vegetated and un-vegetated barrier islands 1 to 8 miles offshore in the Beaufort Sea and wet tundra typical of the coastal plain. The topography is flat and interrupted only by an occasional pingo (a tundra-covered ice hill). The area includes numerous shallow lakes, which compose 20 percent of the coastal plain, and flowing waters such as the Kuparuk and Ugnuravik rivers. The region's habitat contains diverse fish and wildlife.

3.2.1 Routes of Travel to Open Water [18 AAC 75.425(e)(3)(B)(i)]

A spill on the facility pad will remain on the pad unless the spill is near the pad edge. Fuel transfers are not allowed near pad edges in order to mitigate this risk.

A spill from the Kuparuk Pipeline where it crosses the Kuparuk River would enter the river. If not encountered quickly, the discharged oil could enter the marine environment in Gwydyr Bay. Large spills at Kuparuk, particularly well blowouts and pipeline ruptures, have the potential to reach open water and/or ice. See ACS *Technical Manual,* Volume 2, Map Atlas Sheets 28, 35, 40, 54, 61, 63, and 69.

Based on 60 U.S. Geological Survey (USGS) hydrologic reports for July, August, and September of 1970 through 1998 (personal communication from R. Kemnitz, USGS Water Resources, Fairbanks), the following river speed information for the Kuparuk River was obtained:

KUPARUK RIVER SPEED

AVERAGE MPH	MINIMUM MPH	MAXIMUM MPH
1.3	0.4	3.4

This information was used to determine the Kuparuk River velocity in Scenario 3, "Crude Oil Pipeline Rupture Over Kuparuk River to Open Water," in Section 1.6.3.

3.2.2 Response Planning Standard Volume to Open Water

Blowout in Summer: The receiving environment is open water, gravel pad, and tundra. The response planning standard ([redacted] of which approximately 10 percen [redacted]) reaches tundra ponds.

(b) (3)

Crude Oil Transmission Pipeline Spill to Kuparuk River in Summer: The receiving environment is the Kuparuk River. The adjusted RPS volume for a spill from the Kuparuk Pipeline is [redacted], all (100 percent) of which reaches open water.

(3)

Storage Tank Rupture: The receiving environment is a gravel pad, lined secondary containment basin, tundra, and open water (East Lake). The adjusted RPS volume for the oil storage tank at Kuparuk CPF-2 [redacted] its outlet stream during periods of open water.

3.3 COMMAND SYSTEM [18 AAC 75.425(e)(3)(C)]

At Kuparuk, all emergency response situations use the Incident Command System (ICS) structure. Under this system, the first person discovering or responding to an emergency situation becomes the Incident Commander (person in charge) until that individual relinquishes authority to another person better able to control the situation. A description of CPAI's Incident Management Team (IMT) structure, and the general roles and responsibilities associated with various positions, is provided in the CPAI's *Incident Management Handbook,* which is available to all CPAI IMT members to assist them in their assigned roles.

The organizational structure of the IMT is fully staffed and trained in the National Incident Management System (NIMS) ICS and incident management. An organization chart is provided in Figure 3-1**.** The team is based primarily at Kuparuk, with supplemental teams in Anchorage. The IMT may also be supplemented, as necessary, by ACS organization. Figure 3-2 provides an overview of the IMT positions' functions and responsibilities.

Table 3-2 is a notification listing of the IMT for Kuparuk. In this table, the specific IMT position is listed along with the name of the CPAI employee who is assigned to that position. Even though most of the CPAI positions are alternate positions, back-ups are provided for the critical IMT positions. For those CPAI positions without an alternate, designated step-ups, with the full authority to act in that position, are assigned in the event that person is not on the Slope. For a Level II or III event, the North Slope Operations Manager or his step-up is the Incident Commander. The Qualified Individual (QI) would be notified during call-out of the IMT (Level II or III response). The QI and/or Incident Commander will determine if needs for additional IMT personnel or resources requires activation of the ConocoPhillips Global Incident Management Assist Team (IMAT). The Global IMAT is comprised of personnel and resources from ConocoPhillips' worldwide operating business units, departments, or subsidiaries. The Global IMAT may be called upon to augment or fill positions on the IMT. Activation of the Global IMAT is initiated by calling the ConocoPhillips Crisis Hotline at 1-800-342-5119.

The second level of response is the Kuparuk Spill Response Team (SRT). This team consists of operations and maintenance personnel trained in advanced spill containment and cleanup strategies and techniques for large crude oil, diesel, glycol, and salt- or produced-water spills. The SRT will provide expertise, additional supervision, and response direction, and will arrange for additional manpower support, if necessary, to support or take over overseeing on-site cleanup.

For major spills of hazardous materials, or for Resource Conservation and Recovery Act (RCRA) hazardous waste spills that the SRT is not trained to respond to, the Hazardous Materials Response Team (HMRT) would be called in. This team is managed by the North Slope Emergency Response Chief. The HMRT is equipped to clean up hazardous material spills that involve water, tundra, or gravel surfaces. The North Slope Emergency Response Chief and HMRT are responsible not only for containing hazardous material and RCRA hazardous waste spills, but also for cleaning up and working with the spill generator, a HAZMAT contractor if necessary, and the Health, Safety, and Environment (HSE) Team to dispose of the hazardous material.

For spills that exceed the manpower resources and response expertise of the Kuparuk SRT or HMRT, CPAI maintains master service agreements for spills cleanup, and packaging for spills of RCRA and other hazardous and non-hazardous material. During a response effort, contractors are managed through the ICS in the same manner as Kuparuk's full-time response force.

For significant oil spills, there may be On-Scene Coordinators from the federal, state, and local governments, as well as CPAI and the responsible party. These individuals will become part of the Unified Command, representing their organization. Each contributes to the process of:

- Determining and establishing overall incident objectives and priorities;
- Selecting strategies;
- Planning for tactical activities;
- Conducting integrated tactical operations; and
- Using resources efficiently and effectively.

The responsible party will be the Incident Commander in the Unified Command unless the State or Federal On-Scene Coordinator determines the response is inadequate. In that event, either the State or Federal On-Scene Coordinator will assume the Incident Commander's duties. The Unified Command will include a representative from the North Slope Borough that will act as the Local On-Scene Coordinator.

FIGURE 3-1:
INCIDENT MANAGEMENT TEAM ORGANIZATIONAL STRUCTURE

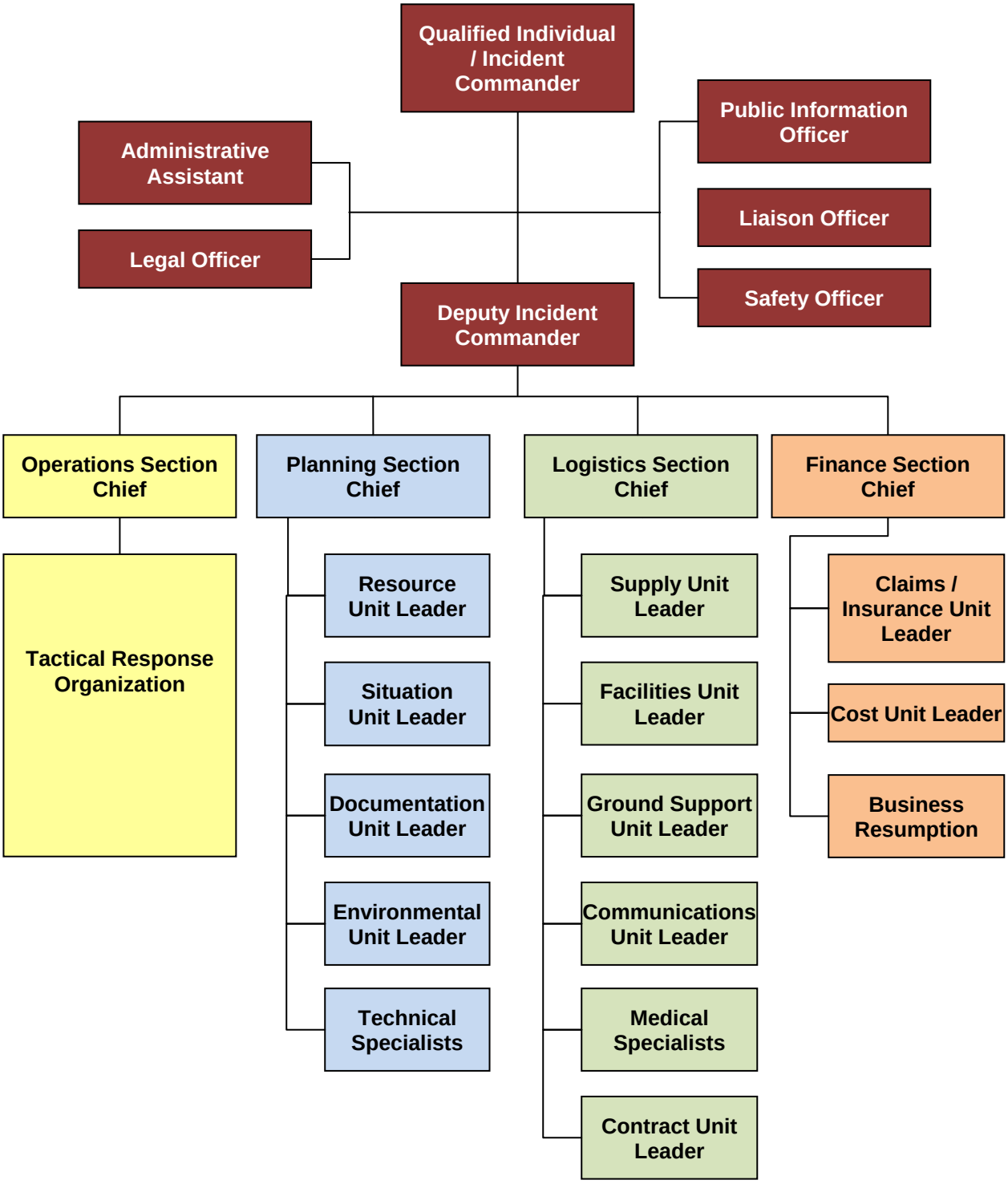

FIGURE 3-2:
IMT FUNCTIONS AND RESPONSIBILITIES CHECKLISTS

QUALIFIED INDIVIDUAL / INCIDENT COMMANDER

The Incident Commander (IC) is the responsible party's (RP's) representative in Unified Command (UC), as applicable, and leads the RP's response effort. Based on the size and complexity of the incident, the IC will work with the United States Coast Guard and state agencies to establish a UC. The IC/UC works with the federal and state On-Scene Coordinators to make decisions including those involving the response objectives/priorities, safety stand downs, expansion/contraction of the response team and the approval of the Incident Action Plan (IAP).

- ✓ Serve as point of contact for RP personnel in initial response.
- ✓ Review general ICS procedures and common responsibilities.
- ✓ Ensure adequate safety measures are in place.
- ✓ Obtain a briefing from the prior IC (201 Briefing), if applicable.
- ✓ Determine incident objectives and general direction for managing the incident.
- ✓ Ensure regulatory notifications have been completed.
- ✓ Establish an ICP.
- ✓ Establish appropriate communications with FOSC, SOSC, and other federal and state officials, as appropriate.
- ✓ Notify and activate oil spill removal organizations, as appropriate.
- ✓ Brief Command and general staff.
- ✓ Establish an appropriate organization.
- ✓ Ensure planning meetings are scheduled as required.
- ✓ Approve and authorize the implementation of an IAP.
- ✓ Coordinate activity for all Command and general staff.
- ✓ Coordinate with key people and officials.
- ✓ Approve requests for additional resources or for the release of resources.
- ✓ Keep agency administrator informed of incident status.
- ✓ Authorize release of information to the news media.
- ✓ Ensure ICS 209 is completed and forwarded to appropriate higher authority.
- ✓ Order the demobilization of the incident when appropriate.

For further information regarding ICS position roles and responsibilities, consult ConocoPhillips' Incident Management Handbook.

FIGURE 3-2 (CONTINUED):
IMT FUNCTIONS AND RESPONSIBILITIES CHECKLISTS

SAFETY OFFICER

During a response, the Safety Officer and safety team(s) ensure the safety of both responders and the general public. The Safety Officer and safety team(s) are tasked with completing safety ICS forms and plans for the response, which are approved by the Safety Officer before submitting them to IC/UC.

- ✓ Become familiar with all applicable national, state, and local health and safety regulations.
- ✓ Participate in tactics and planning meetings, and other meetings and briefings as required.
- ✓ Develop the Site Safety Plan and publish Site Safety Plan summary (ICS Forms 201-5/208) as required.
- ✓ Identify hazardous situations associated with the incident.
- ✓ Review the IAP for safety implications.
- ✓ Provide safety advice in the IAP for assigned responders via the safety message on each ICS 204.
- ✓ Exercise emergency authority to stop and prevent unsafe acts.
- ✓ Investigate accidents that have occurred within the incident area.
- ✓ Review and approve the Medical Plan (ICS Form 206).
- ✓ Develop the Safety Analysis Worksheet (ICS 215A) as required.
- ✓ Ensure all required agency forms, reports, and documents are completion prior to demobilization.
- ✓ Brief Command on safety issues and concerns.
- ✓ Maintain individual log (ICS 214a).

For further information regarding ICS position roles and responsibilities, consult ConocoPhillips' Incident Management Handbook.

FIGURE 3-2 (CONTINUED):
IMT FUNCTIONS AND RESPONSIBILITIES CHECKLISTS

OPERATIONS SECTION CHIEF

The Operations Section Chief, a member of the General staff, is responsible for the management of all operations directly applicable to the primary objectives of the response. The Operations Section Chief is the leader of the Operations Section, which is directed by IC/UC.

- ✓ Obtain briefing from IC.
- ✓ Request sufficient section supervisory staffing for both operations and planning activities.
- ✓ Identify kind and number of resources required to support selected strategies.
- ✓ Subdivide work areas into manageable units.
- ✓ Develop work assignments and allocate tactical resources based on strategy requirements.
- ✓ Prepare ICS 234 work analysis matrix with Planning Section Chief to ensure strategies and tactics and task are in line with ICS 202 response objectives to develop ICS 215.
- ✓ Participate in the planning process and the development of the tactical portions (ICS 204 and ICS 220) of the IAP.
- ✓ Assist with development of long-range strategic, contingency, and demobilization plans.
- ✓ Supervise Operations Section personnel.
- ✓ Monitor need for and request additional resources to support operations as necessary.
- ✓ Evaluate and monitor current situation for use in next operational period planning.
- ✓ Interact and coordinate with Command on achievements, issues, problems, significant changes, special activities, evens, and occurrences.
- ✓ Troubleshoot operational problems with other IMT members.
- ✓ Supervise and adjust operations organization and tactics as necessary.
- ✓ Participate in operational briefings to IMT members as well as briefings to media and visiting dignitaries.
- ✓ Develop recommended list of section resources to be demobilized, and initiate recommendation for release when appropriate.
- ✓ Receive and implement applicable portions of the incident Demobilization Plan.

For further information regarding ICS position roles and responsibilities, consult ConocoPhillips' Incident Management Handbook.

FIGURE 3-2 (CONTINUED):
IMT FUNCTIONS AND RESPONSIBILITIES CHECKLISTS

PLANNING SECTION CHIEF

The Planning Section collects, evaluates, disseminates, and uses incident information for planning operations for the next operating period and for strategic planning (long range). It maintains assigned resource status, and plans for future response activities, prepares the IAP, documents the incident response, tracks incident resources, coordinates Environmental Unit activities, oversees the display of the Situation Status Board produced by the Situation Unit, and demobilizes resources through the Demobilization Unit as necessary.

- ✓ Collect, process, and display incident information.
- ✓ Supervise preparation of the IAP.
- ✓ Facilitate planning meetings and briefings.
- ✓ Assign personnel already on site to ICS organizational positions as appropriate.
- ✓ Establish information requirements and reporting schedules for Planning Section units (e.g., Resources, Situation).
- ✓ Determine the need for any specialized resources in support of the incident.
- ✓ Establish special information collection activities as necessary (e.g., weather, environmental, toxics, etc.).
- ✓ Assemble information on alternative strategies.
- ✓ Keep IMT apprised of any significant changes in incident status.
- ✓ Compile and display incident status information.
- ✓ Oversee preparation and implementation of the incident Demobilization Plan.
- ✓ Incorporate plans (e.g., traffic, medical, communications, site safety) in the IAP.
- ✓ Develop other incident-supporting plans (e.g., salvage, transition, security).
- ✓ Assist Operations with development of the ICS 234 work analysis matrix.
- ✓ Maintain Unit Log (ICS 214).

For further information regarding ICS position roles and responsibilities, consult ConocoPhillips' Incident Management Handbook.

FIGURE 3-2 (CONTINUED):
IMT FUNCTIONS AND RESPONSIBILITIES CHECKLISTS

LOGISTICS SECTION CHIEF

The Logistics Section provides necessary facilities, services, equipment, and supplies to support the incident response. The Logistics Section Chief activates and supervises the Service Branch and the Support Branch within the Logistics Section and reports directly to IC/UC as a member of the General Staff. The Logistics Section Chief coordinates with the other sections of the IMT to plan for the current and future operational periods in order to support the response objectives set by IC/UC.

- ✓ Plan the organization of the Logistics Section.
- ✓ Assign work locations and preliminary work tasks to section personnel.
- ✓ Notify the Resources Unit of the Logistics Section units activated, including names and locations of assigned personnel.
- ✓ Assemble and brief Logistics Branch Directors and Unit Leaders.
- ✓ Determine and supply immediate incident resource and facility needs.
- ✓ In conjunction with Command, develop and advise all sections of the IMT resource approval and requesting process.
- ✓ Review proposed tactics for upcoming operational period for ability to provide resources and logistical support.
- ✓ Identify long-term service and support requirements for planned and expected operations.
- ✓ Advise Command and other Section Chiefs on resource availability to support incident needs.
- ✓ Provide input and review the Communications Plan, Medical Plan, and Traffic Plan.
- ✓ Identify resource needs for incident contingencies.
- ✓ Coordinate and process requests for additional resources.
- ✓ Develop recommended list of section resources to be demobilized and initiate recommendation for release when appropriate.
- ✓ Receive and implement applicable portions of the incident Demobilization Plan.
- ✓ Ensure the general welfare and safety of Logistics Section personnel.
- ✓ Maintain Unit Log (ICS 214).

For further information regarding ICS position roles and responsibilities, consult ConocoPhillips' Incident Management Handbook.

FIGURE 3-2 (CONTINUED):
IMT FUNCTIONS AND RESPONSIBILITIES CHECKLISTS

FINANCE SECTION CHIEF

The Finance Section manages financial aspects of the incident response, including tracking the incident cost, processing invoices and payments, paying claims, and negotiating vendor contracts and pricing. The Finance Section Chief, a member of the General Staff, leads the Finance Section and is directed by IC/UC. The Finance Section Chief activates and supervises the Time/Cost Unit, the Procurement Unit, and the Compensation/Claims Unit, when necessary.

- ✓ Participate in incident planning meetings and briefings as required.
- ✓ Review operational plans and provide alternatives where financially appropriate.
- ✓ Manage all financial aspects of an incident.
- ✓ Provide financial and cost analysis information as requested.
- ✓ Gather pertinent information from briefings with responsible agencies.
- ✓ Develop an Operating Plan for the Finance/Admin Section; fill supply and support needs.
- ✓ Determine the need to set up and operate an incident commissary.
- ✓ Meet with assisting and cooperating agency representatives, as needed.
- ✓ Maintain daily contact with agency(ies) administrative headquarters on finance/admin matters.
- ✓ Ensure all personnel time records are accurately completed and transmitted to home agencies, according to policy.
- ✓ Provide financial input to demobilization planning.
- ✓ Ensure all obligation documents initiated at the incident are properly prepared and completed.
- ✓ Brief agency administrative personnel on all incident-related financial issues that require attention or follow-up prior to leaving the incident.
- ✓ Develop recommended list of section resources to be demobilized and initial recommendation for release when appropriate.
- ✓ Receive and implement applicable portions of the incident Demobilization Plan.
- ✓ Maintain Unit Log (ICS 214).

For further information regarding ICS position roles and responsibilities, consult ConocoPhillips' Incident Management Handbook.

TABLE 3-2:
INCIDENT MANAGEMENT TEAM NOTIFICATION LISTING

NAME	WORK #
COMMAND SECTION	
Incident Commander	
Bill Arnold	659-7253 or 263-4822
Deputy Incident Commanders	
Steve Bradley	659-7219
Glynn Jones	659-7042
Larry Baker	659-7042
Dennis Melton	659-7682
Philip Susen	659-7682
Mark Chaney	659-7727
Kevin Snow	659-7727
Michael Morris	659-7222
David Todd	659-7222
Les Hardesty	659-7931
Jeff May	659-7931
Jay Murali	659-7384
Jerome De La Cruz	659-7384
Liaison Officer	
Jeff Carlson	659-7590
Richard Brazier	659-7590
Safety Officer	
Rick Kuhlman	659-7220
Ed Peace	659-7220
Todd Farish	659-7646
Mike H. Rodriguez	659-7348
Gary Gauthier	659-7348
Bert Bertolini	659-7007
Mike Wood	659-7007
Steve Kravetz	659-7320
Derek Crane	659-7320
Michael Davis	659-7605
Mike Matson	659-7605
Tom Strother	659-7605

TABLE 3-2 (CONTINUED):
INCIDENT MANAGEMENT TEAM NOTIFICATION LISTING

NAME	WORK #
OPERATIONS SECTION	
Section Chief	
Larry Baker	659-7042
Glynn Jones	659-7042
Alternate Section Chiefs	
Mark Chaney	659-7727
Kevin Snow	659-7727
Dennis Melton	659-7682
Philip Susen	659-7682
Les Hardesty	659-7931
Jeff May	659-7931
Jay Murali	659-7384
Jerome De La Cruz	659-7384
Randy Roberts	659-7061
Roy Thornton	659-7778
Scott Collins	659-7778
Malcolm Huson	659-7008
Dana Parker	659-7008
Dispatchers	
Eric Lord	659-7949
Wayne Vanderbilt	659-7949
Source Control Tactical Response	
Brian O'Dell	659-7235
Vance Yoakum	659-7235
MJ Loveland	659-7043
Perry Klein	659-7043
Bobby Morrison	659-7726
Martin Walters	659-7224
Scott Heim	659-7226
Michael Hazen	659-7032
Scott Collins	659-7778
Deputy OPS Section Chief (Field)	
Boyd Follett	659-7494
Jason Elson	659-7494
Kuni Diorec	659-7882
Ed French	659-7882
Kent Ingalls	659-7919
John Parson	659-7919
Barron Rutherford	659-7879
Tad Smith	659-7879

TABLE 3-2 (CONTINUED):
INCIDENT MANAGEMENT TEAM NOTIFICATION LISTING

NAME	WORK #
Dave Deccio	659-7693
Chris Balazs	659-7693
Air Operations Manager	
Bob Tomlinson	659-7213
Mitch Doerr	659-7213
Staging Area Manager	
Andy Lachinski	659-7948
Duane McKenzie	659-0238
Staging Area Assistant	
Sheri Stoaks	659-7142
Marie Sheperd	659-7142
Brady Duffy King	659-7948
Phillip Ivarie	659-7948
Tim Epple	659-7948
Ed Vnenchak	659-7842
Carin Copeland	659-7842
Dirk Reister	659-3938
Dale Chalender	659-7948
David Birchmeier	659-7948
Dion Sumner	659-7634
Keith Johansen	659-7948
Travis Mack	659-7948
PLANNING SECTION	
Section Chiefs	
Michael Morris	659-7222
David Todd	659-7222
Alternate Section Chiefs	
Kevin Fox	659-1732
Michael T Smith	659-1732
Brett Alexander	659-7321
Rich Blankenship Jr.	659-7750
Tyde Riopelle	659-7939
Carl Kinney	659-7957
Blayde North	659-7957
Ted Palmer	659-3978
Bill Powell	659-7750

TABLE 3-2 (CONTINUED):
INCIDENT MANAGEMENT TEAM NOTIFICATION LISTING

NAME	WORK #
Documentation	
Lead: Scott Ginn	659-7659
Lead: Annie Nicolet	659-7659
John Bevis	659-7570
Carleen Mangold	659-7570
Becky Jahrig	659-7690
James Alleva	659-7477
Nan Walker	659-7477
Resource Unit	
Lead: Brett Alexander	659-7321
Lead: Scott Glaser	659-7231
Bill Deviny	659-7883
Resource Status Unit Aide	
Teigen Sorensen	659-1721
Kaisha Pedersen	659-1721
Sheila Sandford-Robinson	659-7831
Mary Simmons	659-7797
Mary Kane	659-7797
Situation Unit	
Lead: Tim Vincent	659-7816
Alt Lead: Dan Nielson	659-7483
Alt Lead: Brian McClaskey	659-7483
Michael Tolan	659-7660
Michael Heinz	659-7660
Carol Parks	659-7816
Technical Specialists	
Chris Victors	659-7548
Kenneth Martin	659-7493
Randy Barnes	659-7869
Thomas Vuk	659-7869
Brad Frates	659-7149
Al Dahlquist	659-7773
Mary Beth Smith	659-7109
Environmental Unit	
Kristy McCullough	659-7242
Jim Short	659-7242
Wendy Mahan	659-7212

TABLE 3-2 (CONTINUED):
INCIDENT MANAGEMENT TEAM NOTIFICATION LISTING

NAME	WORK #
LOGISTICS SECTION	
Section Chiefs	
Gary Eoff	659-7448
Ron Rogalsky	659-7448
Alternate Section Chiefs	
Kirk Allen	659-7402
Tom Winter	659-7351
Neal Collins	659-7239
Paul Sindorf	659-7239
Tom Brown	659-7351
Bob Wilkinson	659-7402
Lissa Scott	659-7361
Warehouse Support	
Robert Snively	659-7583
Duke Reich	659-7583
Ernie Welton	659-7208
Brian Randall	659-7208
Tim Brosius	659-7106
Support Branch – Supply Unit	
Tom Winter	659-7402
Neal Collins	659-7239
Paul Sindorf	659-7239
Tom Brown	659-7361
Lissa Scott	659-7361
Kirk Allen	659-7402
Jena Richards	659-7954
David Harris	659-7361
Brad McCourt	659-7710
Steve Kuffner	659-7710
Yvonne Keith	659-7780
Mike Moore	659-7780
Howard Patten	659-7372
Scott Lardent	659-7920
Jason Groves	659-7100
Patrick McMahon	659-7851
Bruce Brattain	659-7336
Bob Wilkinson	659-7402
Russell Stewart	659-7056
Judy Bjorhus	659-7100

TABLE 3-2 (CONTINUED):
INCIDENT MANAGEMENT TEAM NOTIFICATION LISTING

NAME	WORK #
Support Branch – Food/Facilities Unit	
Steven Garrett	659-7250
Roy Outcelt	659-7250
Support Branch – Transportation	
David Jewell	659-7657
Bob Pillifant	659-7657
Alan Kendrick	659-7056
Phil King	659-7439
Kurt Armstrong	659-7439
Ken Wagner	659-7056
Service Branch – Security Unit	
Bob Tomlinson	659-7213
Mitch Doerr	659-7213
Service Branch – Communication Unit	
Joe Roberts	659-7200
Sally Chryst	659-7200
Glen Hoefer	659-7400
Dave McGraw	659-7400
Robert Lukacinsky	659-7800
Shannon Jardine	659-7800
Mark Bowers	659-7299
Christian Wilkins	659-7299
John Huffman	659-7123
Mike Roy	659-7123

3.4 REALISTIC MAXIMUM RESPONSE OPERATING LIMITATIONS [18 AAC 75.425(e)(3)(D)]

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3.4.1 Introduction

Realistic maximum response operating limitations that might be encountered at the facility are described in the ACS *Technical Manual*, Volume 1, Tactic L-7, which is incorporated into this plan by reference. Tactic L-7 analyzes the frequency and duration, expressed as a percentage of time, of limitations that would render mechanical response methods ineffective, as required by 18 AAC 75.425(e)(3)(D). The analysis considers weather, sea conditions, ice, daylight hours, and other environmental conditions that might influence the efficiency of the oil spill response.

Broken ice conditions limit mechanical oil containment boom and recovery skimmers. As ice coverage increases, it becomes more difficult to maintain containment boom configurations and skirts to concentrate oil for recovery. Field tests in July 2000 demonstrated the effects of broken ice on a containment boom system (Bronson, 2002). However, broken ice conditions can promote oil removal by in situ burning.

3.4.2 Weather and Ice Conditions during the Shoulder Seasons

The following general description of break-up and freeze-up applies to the marine environment in the Prudhoe Bay region. Descriptions are of typical conditions. They cover the chronology of break-up and freeze-up. See Vaudrey and Dickins et al. (2000) and tables in Atwater (1991) for further site-specific details.

May

The Sagavanirktok River and Kuparuk River overfloods (Condition 5) commence on average May 20 and 27, respectively, based on 16 years of analysis. See DF Dickins Associates et al. (2000) for descriptions of seasonal ice conditions.

During break-up, the Kuparuk River floods and typically results in a temporary closure of the Spine Road at the Kuparuk Bridge crossing in late May or early June. Since 2000, Spine Road closure due to flooding of the Kuparuk River has occurred for as little as one day and as many as ten days. Because Kuparuk maintains its own IMT, spill response center, spill response personnel, and spill response team, Spine Road closures do not impact CPAI's response to the majority of spill incidents at Kuparuk. In the event of a large spill that would require Mutual Aid resources, BPXA's Milne Point spill response equipment and team would be mobilized per the North Slope Operators Mutual Aid agreement. Milne Point is located on the west side of the Kuparuk River, so its participation in a spill event would not be affected by the Kuparuk River flooding. In the event of a worst case discharge during a period when the road is closed, additional heavy-lift aircraft would be mobilized to the North Slope to shuttle heavy equipment from Deadhorse to Kuparuk. Response and agency personnel would be transported to Kuparuk from Deadhorse via Shared Services Aviation.

June

June 1-10: Landfast ice is intact (Condition 4) beyond the Kuparuk River and Sagavanirktok River overflood boundaries. Within the overflood zones immediately off the river deltas, fast ice lifts off the bottom of the Beaufort Sea and rapidly melts in place from the relatively warm water discharge (Conditions 6 and 7). The peak of major flooding occurs during the period June 4-7 (±6 days), at which point the Kuparuk River overflood may reach within 1 mile of the Northstar Island (Condition 5). Routine ice road operations might cease at this time. First open water appears offshore of the Sagavanirktok River and Kuparuk River by June 6 to 13, respectively, on average. Fast ice beyond the overflood zones and outside the barrier islands is still intact and more than 5 feet thick in early June.

June 15-20: Nearshore lagoon areas affected by the Kuparuk overflood and shallow waters off the Sagavanirktok delta become mostly free of ice (Condition 9). Fast ice offshore remains intact (e.g., Stump Island to Northstar) and continues to melt (Condition 7). Solid ice 4 to 5 feet thick still surrounds Northstar Island. The soft surface is 25 percent covered by meltwater pools (Condition 6).

Air temperatures average 35^{o}F and range from 20^{o}F to 40^{o}F. The wind is variable but blows 60 percent of the time from the east and northeast, averaging 10 knots.

The ice can support response vehicles up to several weeks before break-up. The effect of deteriorating sea ice on access with specific equipment is illustrated in ACS *Technical Manual,* Tactic L-7, based on field trials by Coastal Frontiers (2001).

July, August, and September

July 1: A completely intact, deteriorated ice cover 3 to 4 feet thick, with many cracks and approximately 40 to 50 percent of its surface covered by melt pools and holes still exists in deeper water in the vicinity of Northstar (Condition 6).

July 4 (Typical): Break-up begins with fracturing and movement in the floating landfast ice (Condition 7).

July 8-12: Remaining fast ice outside the barrier islands, off the Sagavanirktok River delta and in Prudhoe Bay decreases to less than seven-tenths coverage (Condition 8).

July 15-26: Open, ice-free water out to Northstar and surrounding West Dock and Endicott causeway (Condition 9).

Air temperatures average 40°F in July.

The median number of days with flooded and/or broken ice at break-up at production facilities range from 12 days at Point McIntyre to 22 days at Northstar.

October

October 4, ±8 days: Freeze-up begins along shore in shallow water. Ice becomes shore fast for the season within one week following freeze-up in the nearshore lagoons (e.g., Point McIntyre 2 and Niakuk) and by October 25 offshore.

Additional time is required for the young ice sheet to gain sufficient thickness and stability to be judged safe for over-ice operations. Time from initial freeze-up to commencing on-ice operations with response

equipment ranges on average from 40 to 43 days at coastal or nearshore locations (e.g., Point McIntyre 1, Niakuk, and Endicott), to 55 days at Northstar.

Air temperatures at freeze-up range from 5°F to 15°F. Daylight is 9 to 10 hours per day.

3.4.3 In Situ Burning Response Measures to Reduce Environmental Consequences of a Spill in Ice Conditions

As provided by the Alaska Regional Response Team (ARRT) *The Alaska Federal/State Preparedness Plan for Response to Oil & Hazardous Substance Discharges/Releases (Unified Plan)*, Annex F, Appendix II, "In Situ Burning Guidelines for Alaska," (ARRT, 2008), oil spill removal during the shoulder seasons can be greatly enhanced by in situ burning. The ice slows the spread of oil, thereby increasing the response equipment's encounter rate with the oil. The ice also provides natural containment, concentrating the oil for burning and recovery. In situ burning in shoulder season ice conditions generally involves selective burning of oil on melt pools and in leads between floes, followed by manual recovery of residue.

Operational Capability for In Situ Burning in Ice

ACS maintains an inventory of specialized equipment for in situ burning operations during shoulder season ice conditions.

ACS *Technical Manual* Tactics B-1 and B-3 through B-7 describe response strategies, procedures, and equipment to implement a successful burn in a mix of solid ice, broken ice, and open water situations. The tactics descriptions are listed below and are incorporated by reference into this plan.

- B-1 In Situ Burning Plan (including an ARRT burn application form and decision tree);
- B-3 In Situ Burning with Helitorch and Other Igniters;
- B-4 Deployment and Use of Fire Containment Boom;
- B-5 Burning Oil Pools on any Solid Surface;
- B-6 Residue Recovery; and
- B-7 Burn Extinguishment on Water (applicable to fire booms in light ice cover).

ACS conducts spill response training courses involving classroom and field exercises to practice the burn Tactics B-1 through B-7 described in the ACS *Technical Manual* several times a year at North Slope locations. The training calendar includes specific courses directly relevant to in situ burning, such as "Air Monitoring – Site Safety and Oil Spill In Situ Burning Techniques."

The training involves a classroom course and a field demonstration with burn pans. The Helitorch is discussed in the classroom and shown in the warehouse. Demonstrations can also involve creating and igniting gelled fuel. Alyeska has pilots familiar with the Helitorch operations and its helicopter is set up for the Helitorch attachment.

The ACS inventory of specialized response equipment on hand to support a large-scale burning operation is summarized in Table 3-3.

TABLE 3-3:
BURNING EQUIPMENT

EQUIPMENT	QUANTITY
Helitorch (55 gal)	6
Helitorch Liquid	600 gallons
Air deployable igniters	1,417
Helitorch batch gel mixers	2
Adopted from ACS inventory – Response Equipment Specifications, ACS *Technical Manual*, Tactic L-6.	

In addition, ACS maintains fire-resistant boom in a mix of sizes (20-, 30- and 42-inch skirts) together with specialized logistics vehicles to access spill sites over a rotting and/or flooded ice surface in May and June (e.g., shallow draft boats). See Tactic L-6 tables describing boom and vessels.

Steps in the decision to use in situ burning are summarized in the ACS *Technical Manual* Tactic B-1. Before using in situ burning, regulatory approval is obtained by first completing the "Alaska Regional Response Team Application for In Situ Burning" and submitting it to the Unified Command according to the ARRT's Unified Plan, Annex F, Appendix II, "In Situ Burning Guidelines for Alaska," (ARRT, 2008). The application contains the incident-specific burn plan.

Once state and federal approvals are granted, the following steps are taken to implement the response:

1. Collect and concentrate the oil using fire-resistant booms in light ice cover or utilize naturally occurring pools of thicker oil in high-ice concentrations and on surface melt pools on solid ice break-up, and in slush and new ice at freeze-up.
2. Ignite the oil using the Helitorch or hand-held igniters, following established safety procedures to avoid flashback or ignition of any ongoing spill source.
3. Monitor the burn, maintaining constant watch on the fire and smoke plume, condition of containment booms (if used) and other safety hazards and issues.
4. Recover and dispose of the burn residue.

Procedures to develop a plan specific to North Slope operations can be found in ACS *Technical Manual* Tactic B-1. Safety procedures and planning in accordance with established guidelines are emphasized throughout the training, preparation, and conduct of in situ burning operations.

In situ burns are monitored to ensure fire does not spread to adjacent combustible material. Care is taken to control the fire and to prevent secondary fires. Personnel and equipment managing the process are protected. The safe working distances from an in situ fire on water depend on the size of the fire and the exposure time, and are summarized in Table 3-4.

TABLE 3-4:
SAFE WORKING DISTANCES FROM THE FIRE

EXPOSURE TIME	DISTANCE FROM FIRE (FIRE DIAMETERS)
Infinite	4
30 minutes	3
5 minutes	2

Aerial ignition with gel by Helitorch or other ignition methods is coordinated, taking into account prevailing weather conditions, oil pool size and distribution, and the need for strict adherence to established safety distances (Table 3-4).

Crews practice the techniques involved with in situ burning at sea that could involve several vessels working in close proximity.

Effectiveness of In Situ Burning in Ice

The consensus of research on spill response in broken ice conditions is that in situ burning is an effective response technique with removal rates exceeding 85 percent in many situations (Shell et al. 1983, SL Ross 1983, SL Ross and DF Dickins 1987, Singsaas et al. 1994). A considerable amount of research has demonstrated in situ burning in broken ice. The research includes several smaller-scale field and tank tests (SL Ross et al. 2003, Shell et al. 1983, Brown and Goodman 1986, Buist and Dickins 1987, Smith and Diaz 1987, Bech et al. 1993, Guénette and Wighus 1996) and one large field test (Singsaas et al. 1994). Most of the tests involved large volumes of oil placed in a static test field of broken ice resulting in substantial slick thicknesses for ignition. The few tests in unrestricted ice fields or in dynamic ice have indicated the efficacy of in situ burning is sensitive to ice concentration and dynamics; and thus, the tendency for the ice floes to naturally contain the oil, the thickness (or coverage) of oil in leads between floes, and the presence or absence of brash or frazil ice which can absorb the oil.

Brash ice is the debris created when larger ice features interact and degrade. Frazil ice is the “soupy” mixture of very small ice particles that forms as seawater freezes.

Oil spilled on solid ice or among broken ice in concentrations equal to or greater than six-tenths has a high probability of becoming naturally contained in thicknesses sufficient for combustion. In lower ice concentrations, oil spill response methods can be used to create and maintain sufficient film thickness to facilitate burning. Fire-resistant booms are examples. Field experience has shown that it is the small ice pieces (e.g., the brash and frazil, or slush, ice) that accumulate with the oil against the edges of larger ice features (floes) and control the concentration (e.g., thickness) of oil in an area, and control the rate at which the oil subsequently thins and spreads. Other factors affecting burn effectiveness include oil weathering processes (e.g., evaporation and emulsification) and mixing energy from waves.

The following discussion summarizes the current state of understanding the scientific principles and physical processes involved with in situ burning of oil on melt pools during the ice-melt phase in June or on water between floes during the break-up period in July, based on SL Ross et al. (2003). Further discussion also covers in situ burning of thinner slicks in mobile broken ice comprised of brash or frazil ice during the freeze-up shoulder season in October.

The success of an in situ burning operation is dependent on the thickness of the oil to be burned. Ignition and burn efficiency are highly dependent upon slick thickness.

For an oil slick on water or ice to become ignited, the oil must be thick enough to insulate itself from the water beneath it. The igniter can heat the surface of thickened oil to the flash point temperature at which the oil produces sufficient vapors to ignite. The rules of thumb for minimum ignition thickness are listed in Table 3-5.

TABLE 3-5:
MINIMUM IGNITABLE THICKNESS ON WATER

OIL TYPE	MINIMUM THICKNESS
Light Crude and Gasoline	1 mm (0.04 inch)
Weathered Crude and Middle-Distillate Fuel Oils (Diesel and Kerosene)	2 to 3 mm (0.08 to 0.12 inch)
Residual Fuel Oils and Emulsified Crude Oils	10 mm (0.4 inch)

The oil removal rate for in situ oil fires is a function of fire size (or diameter), slick thickness, oil type, and ambient environmental conditions. For most large (greater than 3-meter diameter) fires of unemulsified crude oil on water, the “rule-of-thumb” is the burning consumption rate of 3.5 millimeters (mm) per minute. Lighter fuels burn faster, and heavier oils and emulsions burn slower, as shown in Table 3-6.

Burn rate is also a function of the size of the fire. Crude oil burn rates increase from 1 mm per minute for 3-foot diameter fires to 3.5 mm per minute for 15-foot fires and greater. In situ burns on melt pools typically consume oil at 1 mm per minute. For very large fires, on the order of 50 feet in diameter and larger, burn rates may decrease slightly because there is insufficient air in the middle of the fire to support combustion at 3.5 mm per minute. As fire size grows to the 50-foot range, oil type ceases to affect burn rate for the same reason.

TABLE 3-6:
BURN/REMOVAL RATES FOR LARGE FIRES ON WATER

OIL TYPE/CONDITION	BURN/REMOVAL RATE
Gasoline >10 mm (0.4 inch) thick	4.5 mm/min (0.18 in/min)
Distillate Fuels (diesel and kerosene) >10 mm (0.4 inches) thick	4.0 mm/min (0.16 in/min)
Crude Oil >10 mm (0.4 inch) thick	3.5 mm/min (0.14 in/min)
Heavy Residual Fuels >10 mm (0.4 inch) thick	2.0 mm/min (0.08 in/min)
Slick 5 mm thick*	90 percent of rate stated above
Slick 2 mm thick*	50 percent of rate stated above
Emulsified oil (percent of water content)**	Slower than above rates by a factor equal to the water content percent
Estimates of burn/removal rate based on experimental burns and should be accurate to within ±20 percent.	

* Thin slicks will naturally extinguish, so this reduction in burn rate only applies at the end of a burn.

** If ignited, emulsions will burn at a slower rate almost proportional to their water content (a 25 percent water-in-crude-oil emulsion burns about 25 percent slower than the unemulsified crude).

An in situ oil fire extinguishes naturally when the slick burns down to a thickness that allows enough heat to pass through the slick to the water to cool the surface of the oil below the temperature required to sustain combustion. The thickness at which an oil fire on water extinguishes is related to the type of oil

and initial slick thickness. The rules of thumb are presented in Table 3-7. Other secondary factors include environmental effects such as wind (winds greater than 20 knots preclude in situ burning in most cases) current herding of slicks against barriers, and oil weathering.

TABLE 3-7:
FIRE EXTINGUISHING SLICK THICKNESS

OIL TYPE/INITIAL SLICK THICKNESS	EXTINGUISHING THICKNESS
Crude Oil up to 20 mm (0.8 inch) thick	1 mm (0.04 inch)
Crude Oil 50 mm (2 inches) thick	2 to 3 mm (0.08 to 0.12 inch)
Distillate Fuels any thickness	1 mm (0.04 inch)

With an estimate of the initial thickness of a fully contained slick, or a measure of the burn time, it is relatively easy to estimate oil removal efficiency by burning. If not all the slick area is on fire; the calculations need to account for this.

Oil removal efficiency by in situ burning may be summarized as a function of the following key factors:

- Initial thickness of the slick,
- Thickness of the residue remaining, and
- Amount of the slick's surface that was on fire.

The water current maintains the oil thickness in the apex of a fire-resistant boom under tow, or against an ice edge in wind or current. When burning in a current, the fire slowly decreases in area until it reaches a size that can no longer support combustion. This herding effect can increase overall burn efficiencies, but it extends the time required to complete each burn.

The residue from a typical efficient (greater than 85 percent removal) in situ burn of crude oil 10 to 20 mm thick is a semi-solid, tar-like layer that has an appearance similar to the skin on an old, poorly-sealed can of latex paint that has gelled. For thicker slicks, typical of what might be expected in a towed fire boom (about 150 to 300 mm), the residue can be a solid. Burn residue is usually denser than the original pre-burn oil, and usually it does not spread due to its increased viscosity or solid nature.

Tests indicate the burn residues from efficient burns of heavier crude oils less than 32 degrees API gravity may sink once the residue cools, but their acute aquatic toxicity is very low or nonexistent. The “In Situ Burning Guidelines for Alaska” (ARRT 2008), state:

> “The environmental advantages of in situ burning outweigh the potential environmental drawbacks of burn residue, including the possible environmental harm if the burn residue sinks. Therefore, the on-scene coordinators do not consider the potential impacts of burn residue when deciding whether to authorize an in situ burn. Nevertheless, the responsible party or applicant is required to have a plan for residue collection.”

Compared with unemulsified slicks, emulsions are much more difficult to ignite and, once ignited, display reduced flame spreading and more sensitivity to wind and wave action. Stable emulsion water contents are typically in the 60 percent to 80 percent range with some up to 90 percent. The oil in the emulsion

cannot reach a temperature higher than 100 degrees Celsius (°C) until the water is either boiled off or removed. The heat from the igniter or from the adjacent burning oil is used first, mostly to boil the water rather than heat the oil.

The following points summarize the effect of water content on the removal efficiency of weathered crude emulsions:

- Little effect on oil removal efficiency (i.e., residue thickness) for water contents up to about 12.5 percent by volume;
- A noticeable decrease in burn efficiency with water contents above 12.5 percent, the decrease being more pronounced with weathered oils; and
- Zero burn efficiency for emulsion slicks having water contents of 25 percent or more.

Some crudes form meso-stable emulsions that can burn efficiently at much higher water contents. Paraffinic crudes appear to fall into this category.

Fortunately, emulsion formation is slowed dramatically by high ice concentrations and may not be a significant operational factor in planning in situ burns on solid ice or naturally contained in higher concentrations of broken ice.

SL Ross et al. (2003) provides guidelines for burning thin slicks in broken ice with brash and slush, particularly relevant during the break-up and freeze-up shoulder seasons. General rules for minimum ignitable thickness and oil removal rates for burning thin slicks of crude oils on brash and/or slush with broken ice are as follows:

- The minimum ignitable thickness for fresh crude on frazil ice or small brash ice pieces is up to double that on open water, or about 1 to 2 mm.
- The minimum ignitable thickness for evaporated crude oil on frazil ice or small, brash ice pieces can be higher than on open water, but is still within the range quoted for weathered crude on water, about 3 mm with gelled gasoline igniters.
- For a given spill diameter, the burn rate in calm conditions is about halved on relatively smooth frazil/slush ice and halved again on rougher, brash ice. Wave action slightly reduces the burn rate on open water, but the halving rule seems to apply in waves as well.

The residue remaining on broken ice in calm conditions is about 50 percent greater than that on open water, or 1.5 mm. The residue remaining on brash or frazil ice in waves is slightly greater than in calm conditions, at about 2 mm.

In summary, in situ burning of oil is efficient and rapid in broken ice conditions under the following conditions:

- The spilled oil is thicker than the minimum ignitable thickness (a thickness of 2 to 3 mm results in 50 to 66 percent removal efficiency: 10-mm thickness, a typical thickness for wind-herded slicks on melt ponds on ice, gives 90 percent removal efficiency);
- Larger areas can be ignited (a 100-square-foot slick on a melt pool will burn at 3.5 barrels of oil per hour [boph], a 50-foot diameter, 10-mm thick slick will burn at 300 boph and a 100-foot-diameter slick will burn at 1,200 boph); and
- The oil is not more than 25 percent emulsified.

3.5 LOGISTICAL SUPPORT [18 AAC 75.425(e)(3)(E)]

CPAI has an existing logistical support infrastructure for its operations on the North Slope. Transportation equipment, coordination procedures, and maintenance procedures are in place under normal operations. CPAI has contracts for operational logistical support to support a spill response.

ACS *Technical Manual,* Volume 1, Tactics L-3, L-4, and L-8 through L-10 are incorporated here by reference.

3.6 RESPONSE EQUIPMENT [18 AAC 75.425(e)(3)(F)]

3.6.1 Equipment Lists

The ACS *Technical Manual,* Volume 1 lists contracted or other oil discharge containment, control, cleanup, storage, transfer, lightering, and related response equipment to meet the applicable RPS in Part 1, and to protect environmentally sensitive areas and areas of public concern in Part 3, and that may be reasonable expected to suffer an impact from a spill of the RPS volume as described in the response scenarios in Section 1.6.3. The location, inventory, and ownership information for the equipment is listed in ACS *Technical Manual* Tactic L-6. The time frame for delivery and startup of response equipment and trained personnel located outside the facility's primary region of operation is outlined in the response scenarios in Part 1. The manufacturer's rated capacities, limitation and operational characteristics for each item of oil recovery equipment listed in the response scenarios are described in ACS *Technical Manual* Tactic L-6. Each vessel and the equipment for transferring oil from tanks mentioned in the scenarios in Part 1 are listed in Tactic L-6 as well. See the ACS *Technical Manual*, Volume 2, Map Atlas Sheets 35, 36, 39-42, 46, 51, 53, 54, 57, 61, 63, and 69 for locations and descriptions.

3.6.2 Maintenance and Inspection of Response Equipment

Response equipment is maintained in a condition for immediate use and rapid deployment. The on-site response equipment located at Kuparuk is routinely inspected and tested by Kuparuk personnel. In addition, ACS performs routine inspection and maintenance of all ACS and Kuparuk response equipment.

ACS holds the following U.S. Coast Guard (USCG) Oil Spill Removal Organization (OSRO) classifications:

- River/canal environments: Classes MM, W1, W2, and W3;
- Inland environments: Classes MM, W1, W2, and W3;
- Open ocean environments: Classes MM, W1, and W2;
- Offshore environments: Classes MM, W1, and W2; and
- Nearshore environments: Classes MM, W1, and W2.

ACS has fulfilled the equipment maintenance and testing criteria that this USCG classification requires.

3.6.3 Response Equipment

Spill response equipment and supplies are available for immediate deployment through the North Slope Emergency Response Chief or are pre-staged at the CPFs, drill sites, or along the Kuparuk River and coastline. Special 40-foot-long trailers ("Spill Vans") at the Kuparuk Emergency Operations Center at CPF-1 pad are equipped for moderate to large spills and can be rapidly deployed by towing to the spill

site on the Kuparuk road network. CPF-2 and CPF-3 have a local response spill van that can be rapidly deployed with a pickup truck or front-end loader. These vans are designated as “CPF Spill Vans” and are equipped with minor to moderate spill response equipment available to any SRT member responding to a particular facility. Connex containers located along the Kuparuk River are designated as “River Connexes” and hold containment boom and associated materials. A spill connex container will also be staged at DS-3G to provide containment boom and other response equipment to the DS-3S area.

Several sites are chosen for boom pre-deployment in the Kuparuk River. Kuparuk and ACS personnel deploy diversionary and exclusion boom at three locations downstream of the Kuparuk Pipeline Kuparuk River crossing. Boom is also pre-deployed on Kalubik Creek, downstream from the DS-3S pipeline crossing, and on “No-name” Creek, located east of the DS-3S pad. The proactive plan includes conducting ongoing spill response training to enhance the skills of facility personnel who respond to spills. With each year’s experience in operating in the area of the Kuparuk River, the staging of equipment and sites has varied. The goal is to strategically locate the staged equipment close to sensitive areas and in areas that are easily accessible, allowing for the quick deployment of additional equipment if needed. The staging area for Kuparuk River deployment is the Kuparuk boat launch at the Spine Road bridge. The staging area for Kalubik Creek and No-name Creek deployment operations is DS-3G. Additional boom deployment sites are evaluated annually.

Time Frame of Boom Pre-Deployment

The open-water time frame for Kuparuk River boom deployment activities follows spring break-up, typically occurring in late June or early July, and ends prior to the fall freeze-up, typically in mid-September. The initial boom pre-deployment at all sites is anticipated to take approximately two weeks. Prior to fall freeze-up, all associated spill response equipment will be removed from the river and have maintenance performed, as needed, and will be returned to the appropriate connex staging boxes.

Boom Description and Deployment Location

Pre-deployment sites for the Kuparuk River are at the Spine Road bridge and locations denoted as KUP-3, KUP-4, and KUP-5 on the ACS *Technical Manual,* Volume 2, Map Atlas Sheet 63. The pre-deployment site on Kalubik Creek is located downstream of the pipeline crossing, and on No-name Creek, pre-deployment will be north of DS-3S. Due to seasonal changes of the river channels and weather conditions causing fluctuating river currents, specific boom configurations and exact lengths of boom to be pre-deployed at each site may vary. At each pre-deployment site, sufficient boom sections and anchors are utilized to traverse the water body in a manner that optimizes their intended use for containment and recovery.

3.7 NON-MECHANICAL RESPONSE INFORMATION [18 AAC 75.425(e)(3)(G)]

Non-mechanical response information is provided in the ACS *Technical Manual*. It is CPAI's policy to attempt non-mechanical responses only in situations where mechanical recovery cannot be accomplished without unacceptable environmental damage or unacceptable risk to personnel, or when mechanical recovery cannot be completed before the threat of further migration of contained oil is imminent. In situ burning will not be used as a substitute for mechanical recovery.

The following text is provided with permission by BPXA for use in this ODPCP.

In situ burning equipment inventory and deployment are described in the ACS *Technical Manual* Tactics L-6 and B-1 through B-7, incorporated here by reference.

Oil spill cleanup during the shoulder seasons can be greatly accelerated by in situ burning. The ice slows the spread of oil thereby increasing the encounter rate. The ice also provides natural containment, concentrating the oil for burning and recovery. In situ burning in shoulder season ice conditions generally involves selective burning of oil on melt pools and in leads between floes, followed by manual recovery of residue.

3.7.1 Environmental Consequences

The environmental consequences of in situ burning will be assessed by monitoring the downwind trajectory of the smoke. A trial burn will indicate the path of the smoke. Monitoring the downwind position of the smoke plume will be accomplished by a ground- or air-based member of the IMT.

Appropriate measures as required by the Unified Command, natural resource, and public safety agencies will be carried out to protect nearby human populations and environmentally sensitive areas. In situ burns will be limited to sites that are a minimum safe distance, generally several miles upwind of human populations. The safe distance will be plotted as outlined in the "In Situ Burning Guidelines for Alaska," Revision 1, August 2008. The determination takes into account a trial burn, wind conditions, and size of the expected burn area. In addition, public notifications and warnings will be issued in cooperation with agency emergency staff.

In situ burns conducted according to the Unified Plan are not expected to harm environmentally sensitive areas and areas of public concern. Heat from in situ burning affects only the upper few centimeters of the water column in contact with the oil. Smoke has not been found harmful to wildlife populations. In situ burning smoke is reduced to concentrations that are safe to people by means of burning only at safe distances.

In situ burn operations receive constant visual monitoring of the smoke plume's behavior. The burn operations team visually monitors the smoke plume. The Federal and State On-Scene Coordinators may authorize a trial burn to confirm anticipated plume drift direction and dispersion distances downwind before authorizing the proposed burn. Burn operations may be stopped if the plume contacts or threatens to contact the ground in a populated area.

A step-by-step process in establishing safe distances for burning is fully presented in the "In Situ Burning Guidelines for Alaska," Revision 1, August 2008. The State and Federal On-Scene Coordinators determine whether the burn lies at a safe distance from human populations. In situ burning is not authorized if it does not meet public health regulatory standards. The safe distance separating human

populations from in situ oil burns is the downwind radius from the fire at which smoke particulate matter 2.5 micron diameter concentrations at the ground diminish to 65 micrograms per cubic meter averaged over one hour. The safe distance guidelines are based on the predictions of a National Institute of Standards and Technology (NIST) computer model, ALOFT-Flat Terrain model. The safe distance meets the National Ambient Air Quality Standards for particulate matter over a one-hour time period and is also used as the indicator that human populations will not be exposed to unsafe levels of all other smoke components. Table 3-8 lists the general safe distances separating an in situ burn and downwind, populated areas in flat terrain.

TABLE 3-8:
SAFE DISTANCES BETWEEN IN SITU BURNS AND DOWNWIND HUMAN POPULATIONS IN FLAT TERRAIN: LOCATION OF FIRE ZONES

LOCATION OF FIRE	GREEN ZONE	YELLOW ZONE	RED ZONE
Flat terrain on land	>3 miles	1 to 3 miles	<1 mile
Water <3 miles from shore			
Water >3 miles from shore	>1 mile	Not applicable	<1 mile

Burning at a green zone safe distance from the public is acceptable following Level 1 public notification.

The “In Situ Burning Guidelines for Alaska,” Revision 1, August 2008, allows the results of the NIST modeling to be used to authorize burning on the North Slope. The results show that for fires up to 10,000 square feet in area (about 100 feet in diameter, in all wind speeds modeled over land or water in typical winter and summer atmospheric conditions), the surface concentrations of particulate matter decline below the target concentration in less than 0.6 mile of the burn. Fifty-six scenarios in Cook Inlet and the North Slope were modeled using the ALOFT-FT computer model, and the worst-case predictions were used to develop the safe distances for those specific locations.

The ARRT Unified Plan aims to protect wildlife and habitat threatened by an oil spill by using in situ burning where mechanical methods become inadequate to contain and remove spilled oil. The ARRT’s Science and Technology Committee further decided that in situ burning can reduce the threat to wildlife posed by untreated oil, and that this benefit outweighs the potential harm posed by in situ burning smoke and residue. The Committee also decided not to require the incident-specific identification of wildlife threatened by in situ burning based partly on a report by Campbell et al. (1994) regarding the environmental trade-offs of in situ burning. It concluded that in offshore, nearshore, and estuarine environments, burning a crude oil spill poses less risk to wildlife than not burning. Burning greatly reduces the volume of oil and therefore the probability that oil comes in contact with wildlife. Burning also eliminates the volatile/soluble fraction of the spill.

3.7.2 Operational Capability and Effectiveness of In Situ Burning in Ice

ACS maintains specialized equipment to conduct in situ burning operations during all seasons and all ice conditions as described in Section 3.4.3. The extensive inventory of response equipment is specifically designed to support a large scale burning operation. Text in Section 3.4.3 also describes the effectiveness of in situ burning in ice.

3.8 RESPONSE CONTRACTOR INFORMATION [18 AAC 75.425(e)(3)(H)]

The primary response action contractor is ACS.

Phone:	(907) 659-2405
Fax:	(907) 659-2616
Mailing Address:	Pouch 340022
	Prudhoe Bay, Alaska 99734-0022

CPAI will activate ACS to provide the initial manpower and resources required to respond to a large or lengthy spill response. If additional resources are required, they will be accessed through master service agreements maintained by ACS and through Mutual Aid among North Slope operators. CPAI's Statement of Contractual Terms with ACS for Kuparuk is provided as Figure 3-3. ACS maintains contracts for off-slope response personnel.

FIGURE 3-3:
ALASKA CLEAN SEAS STATEMENT OF CONTRACTUAL TERMS

STATEMENT OF CONTRACTUAL TERMS

AS REQUIRED UNDER AS 46.04.30, AS 46.04.035 and 18 AAC 75.445(i)(1) in fulfillment of a requirement for registration of primary response action contractors and for approval of an Oil Discharge Prevention and Contingency Plan.

PLAN TITLE: Oil Discharge Prevention and Contingency Plans: Alpine Development Area, Kuparuk River Unit, and North Slope Exploration,

PLAN HOLDER: ConocoPhillips,

This statement is a certification to the Alaska Department of Environmental Conservation summarizing the contract between ConocoPhillips, the oil discharge prevention and contingency plan holder (hereafter "PLAN HOLDER"), and Alaska Clean Seas, the oil spill primary response action contractor or a holder of an approved oil discharge prevention and contingency plan under contract (hereafter "CONTRACTOR"), executed on September 10, 2012, and the original of which is located at Alaska Clean Seas, Anchorage Office, as evidence of the PLAN HOLDER's access to the containment, control and/or cleanup resources required under standards at AS 46.04.030 and 18 AAC 75.400 – 18 AAC 75.495. The PLAN HOLDER and the CONTRACTOR attest to the Department that the provisions of this written contract clearly obligate the CONTRACTOR to:

(A) provide the response services and equipment listed for the CONTRACTOR in the contingency plan;

(B) respond if a discharge occurs;

(C) notify the PLAN HOLDER immediately if the CONTRACTOR cannot carry out the response actions specified in this contract or the contingency plan;

(D) give written notice at least 30 days before terminating this contract with the PLAN HOLDER;

(E) respond to a Department-conducted discharge exercise required of the PLAN HOLDER; and

(F) continuously maintain in a state of readiness, in accordance with industry standards, the equipment and other spill response resources to be provided by the CONTRACTOR under the contingency plan.

I hereby certify that, as representative of the PLAN HOLDER, I have the authority to legally bind the PLAN HOLDER in this matter. I am aware that false statements, representations, or certifications may be punishable as civil or criminal violations of law

Nicholas D. Olds 09/12/2012
Signature Date

Name: Nick Olds

Title: Vice President, North Slope Operations and Development

FOR: ConocoPhillips
PLAN HOLDER

I hereby certify that, as representative of the CONTRACTOR, I have the authority to legally bind the CONTRACTOR in this matter. I am aware that false statements, representations, or certifications may be punishable as civil or criminal violations of law.

C. B. Lloyd 9/14/12
Signature Date

Name: Craig Barkley "Bark" Lloyd

Title: President and General Manager

FOR: Alaska Clean Seas
CONTRACTOR

RAC updated 9/1/2012

FIGURE 3-4:
ACS-CPAI MEMBER RESPONSE ACTION CONTRACT SIGNATURE PAGE

Confidentiality and Section 14 – Miscellaneous, will survive such termination.

F. Amendment. This Response Action Contract may be amended only in writing signed by both parties to the Contract.

G. Entire Understanding. The terms set forth in this Response Action Contract supersede all previous discussions, understandings and agreements between the parties hereto with respect to the subject matter hereof, and are intended by the parties as a final, complete and exclusive expression of the terms of their agreement and may not be contradicted, explained or supplemented by evidence of any prior agreement, any contemporaneous oral agreement or any additional terms.

H. Conflicts. This Response Action Contract is to be interpreted in harmony with the ACS Bylaws. In the event of a conflict between the provisions of this Contract and the ACS Bylaws, the terms of the ACS Bylaws shall control.

IN WITNESS WHEREOF, the parties have signed this Response Action Contract, effective the date first written above.

ACS		MEMBER	
Alaska Clean Seas		ConocoPhillips, Alaska Inc.	
Signature:		Signature	
Name:	Brad Hahn	Name:	John Whitehead
Title:	President & CEO	Title:	VP North Slope Operations and Development
Date:	6/17/05	Date:	6/17/05

3.9 TRAINING AND DRILLS [18 AAC 75.425(e)(3)(I)]

Spill prevention and response training is provided for employees, with increased emphasis for members of emergency response teams and the IMT. Computer-based training modules and periodic announced and unannounced drills ensure operators and personnel involved in a response understand their responsibilities under the ODPCP.

At a field-wide level, spill prevention and awareness training is required of all new employees. Training is then provided on a continuing basis through field-wide spill awareness programs and at facility weekly safety meetings, and is required annually by various spill prevention regulations for oil-handling employees at each operating facility.

3.9.1 North Slope Spill Response Team Spill Response Training

The North Slope Spill Response Team (NSSRT) consists of workers who volunteer as emergency spill response technicians. Each team member is required to have initial emergency response training and annual refresher training, which meets or exceeds the requirements in the hazardous waste operations and emergency response (HAZWOPER) regulations, 29 CFR 1910.120(q). Annual requirements for HAZWOPER refreshers, medical monitoring, and respiratory fit test are tracked by ACS (see Section 3.9.5, Recordkeeping). The NSSRT training program is available to responders from production units on the North Slope that utilize ACS as their OSRO. Responders are classified into categories, each with minimum training requirements as described in ACS Tactic A-4 in the ACS *Technical Manual*. The NSSRT maintains a minimum staffing level designed to ensure response capability and to maintain compliance with North Slope ODPCP response scenarios.

Kuparuk SRT members are trained as NSSRT members or are ACS employees. Kuparuk SRT members are trained according to the NSSRT training requirements discussed below; ACS employees may have additional training.

Active Member Requirements

NSSRT members must complete the following minimum annual training activities in order to be considered an active member of the NSSRT:

- 8-Hour HAZWOPER refresher certification,
- Contingency plan review, and
- Completion of five equipment proficiency checks.

The NSSRT training program offers weekly classes at Kuparuk. These classes emphasize hands-on experience, field exercises, and team building drills. The courses are coordinated by the facility Lead Spill Technician (through ACS) in conjunction with field emergency management, and use CPAI, ACS, and external training consultants.

Table 3-9 lists typical NSSRT training courses. Due to operational time constraints, many of the courses are divided by subject area and are taught in the 2- or 3-hour time frame of an NSSRT meeting. The training and attendance is documented and available for review. The yearly training schedule is also available at the facility and at ACS. Current NSSRT training schedules are posted on the ACS web site.

TABLE 3-9:
TYPICAL NORTH SLOPE SPILL RESPONSE TEAM
TRAINING PROGRAM COURSES

CATEGORY	COURSE TITLE
Communication	ICS Basic Radio Procedures
Decontamination	Decontamination Procedures
Environmental	Environmental Awareness
	Wildlife Hazing
Equipment	Basic Hydraulics For Spill Responders
	Boom Construction and Design
	Fastanks and Bladders
	Skimmer Types and Application
	Snow Machines and ATV Operations
	90+ Spill Response Equipment Proficiency Checks
Management	Incident Command System
	Management and Leadership During An Oil Spill
	Quarterly Drill and Exercises
	Staging Area Management
Miscellaneous	Global Positioning System
Response Tactics	In Situ Burning
	Nearshore Operations
	Summer Response Tactics
	Winter Oil Spill Operations
	Winter Response Tactics
Safety/Survival	Arctic Cold Weather Survival
	Arctic Safety
	HAZWOPER
	Spill Site Safety
	Weather Port and Survival Equipment

3.9.2 IMT Member Training

The IMT receives training on the ODPCP through computer-based training modules. ICS training is provided to members of the Kuparuk IMT as frequently as quarterly and no less than annually. Training course curricula are based upon the NIMS ICS structure. NIMS certification is provided for general ICS courses which focus on organization, management, incident action planning, and forms used during an incident response. Section-specific or more specialized IMT courses provide detailed instruction into more complex components of incident responses. Periodic announced and unannounced drills ensure IMT members understand their roles and responsibilities within the ICS and under the ODPCP.

ICS training is also conducted yearly for both the Alpine and Anchorage IMTs. Both of these teams could provide support to the Kuparuk IMT in the event of a response. ACS provides ICS training for its own personnel.

3.9.3 Auxiliary Contract Response Team

ACS maintains and operates a robust training and response program to ensure North Slope operators have the ability to provide the personnel required to support a long-term response. The program consists of contracts and agreements with numerous emergency response service providers and provides assurance that a host of trained and qualified responders are available to respond to oil spills on the North Slope.

3.9.4 Other Training

Operators and facility personnel receive annual training on the Emergency Action Plan, which covers procedures for reporting, notification, alarms, evacuation, and duties to perform during an emergency at Kuparuk facilities and pipelines.

The Kuparuk Fire Team is a registered fire department with the State of Alaska Division of Fire and Life Safety. Firefighters that may be involved in a spill response due to threat of fire, are trained to NFPA standards that permit personnel to be certified as State of Alaska Firefighters at the I and II levels, certified as Driver/Operators of Fire Apparatus and as Certified Fire Officers. Training is conducted in order to ground people in the skills needed as well as providing practical opportunities to become proficient in the tasks needed to operate as a firefighter. Training records are held in an electronic data base for as long as the individual is an active member of the fire department.

3.9.5 Recordkeeping

Training records for CPAI employees with duties under this response plan are maintained by the CPAI HSE Department and/or Human Resources; recordkeeping practices follow written Company policy and applicable retention periods. CPAI employee records are maintained for the period of employment plus a minimum of five years. Records of CPAI employees with assigned duties directly related to operation of DOT-regulated pipelines are maintained until the employee is no longer assigned those duties, plus five years. ACS personnel records are maintained in a database at ACS for the period of employment, plus a minimum of five years. ACS maintains oil spill responder training records for all NSSRT member personnel, including CPAI employees and contractors; records are kept while the person performs duties as an NSSRT member, plus a minimum of five years. The ACS Training Coordinator, or designee, maintains a database as a record of the courses taken by each employee and contractor performing duties as an NSSRT member. The database provides a description of the course and the date completed. Current training status of NSSRT personnel is available from the ACS Training Coordinator.

CPAI requires contractors comply with applicable local, state, and federal regulations. Contractors maintain their own training programs and records. CPAI routinely audits contractor training programs and records to ensure regulatory compliance as part of the CPAI HSE Contactor Audit Program.

CPAI uses National Preparedness for Response Exercise Program (NPREP) guidelines for conducting training and exercises; records are maintained by the Crisis Management and Emergency Response Drills and Training Coordinator.

3.9.6 Spill Response Exercises

CPAI conducts or participates in several types of exercises every year, including SRT field exercises, full-response team field exercises, IMT tabletop exercises which may include field deployments, notification exercises, and spot equipment checks. Most drills are conducted by CPAI, some are conducted by agencies, and others are conducted by ACS or its member companies (Mutual Aid Drills [MAD]).

For all CPAI facilities, exercise and drill events are conducted and evaluated under the authority of the facility or asset manager (who is also the Incident Commander and Qualified Individual [QI]). The QI is always either at the facility or has a designated "step-up" on site with full authority to act on his/her behalf. The QI is a member of the IMT, and all full-response team field drills, tabletop drills, and notification drills incorporate a QI notification drill.

Both announced and unannounced drills are conducted annually. Typically, a control team develops and conducts the drill. An exercise begins when the Notification to Start Response is given to the appropriate party. This team begins the drills by calling the emergency number announcing "This is a drill," followed by the pertinent information. Security then activates the appropriate response organization by using the personnel pager system. Part of the system mobilized in these drills is the sections that notify government agencies, as described in Section 1.2. These notifications can take place as unannounced drills called by external organizations, including government agencies. Unannounced drills are conducted at least annually and may involve tabletop drill activity and/or equipment deployment. If a government agent notifies field personnel that they are triggering a drill, the field personnel notify Security.

Drills are carried out on an average of once per quarter. Actual spill responses can be used to replace a drill during any quarter. If a Mutual Aid member conducts a drill during a quarter that involves a CPAI facility, it would serve as the drill for that CPAI facility for that quarter. Notification drills that include the QI (or Incident Commander) are a part of the quarterly drills. Management tabletop drills are typically conducted annually for the CPAI Kuparuk IMT.

Each drill is critiqued by members of the response team and by third-party reviewers for larger drills. Recommendations and action items are evaluated and incorporated into the response plan where appropriate. The drill schedule requirements (annual and triennial) and description of drill types are provided in Table 3-10 and Table 3-11. The drill schedule meets the NPREP requirements.

TABLE 3-10:
ANNUAL AND TRIENNIAL DRILLS

TYPE	TIMEFRAME		COMMENTS AND DOCUMENTATION[2]
	ANNUAL	TRIENNIAL[1]	
Notification List Update	Every 6 months	6	Documented in internal contact list updates and/or transmittals to agencies.
QI Notification Exercises	4	12	Documentation through attendance rosters, ICS forms, and/or final exercise report.
Tabletop Exercise	1	3	Documentation through attendance rosters, drill ICS forms, and/or final exercise report.
Emergency Procedure Drills for Vessels and Barges	4	12	ACS requirement; can be achieved through Mutual Aid or actual event or training exercises. Documentation through drill plans and critique.
Emergency Procedure Drills for Facilities (NPREP Optional)	4	12	Optional requirement is typically combined with tabletop exercises and QI notification drills. Documentation through attendance rosters, ICS forms, and/or final exercise report.
Equipment Deployment (ACS-owned)	1	3	Can be achieved through Mutual Aid, documentation through drill plans, drill ICS forms, and/or final exercise report.
Equipment Deployment (CPAI-owned)	Semi-annually	6	Mutual Aid and local drills. Must include deployment for the average most probable discharge or substitute real events. Documentation through drill plans, drill ICS forms, and/or final exercise report.
Unannounced Drill	1	3	Documentation through drill plans, drill ICS forms, and/or final exercise report. Equipment deployed during this drill will satisfy the equipment deployment drill. Every 3 years, one drill must include equipment deployment.
Triennial Cycle of Exercising the Entire Plan	During the triennial cycle, all components of the entire response plan must be exercised.	1	Documentation through drill plans, drill ICS forms, and/or final exercise report. Can be completed in segments or completed through other drills if drills meet the 15 plan components.
Area Exercises	20 selected by National Scheduling Coordinating Committee (USCG)		Documentation through drill plans, drill ICS forms, and/or final exercise report. Compliance through Mutual Aid (within specified guidelines).

Notes:

1. The triennial requirement column is the total number of drills or events for the entire three-year period. Additionally, substitutions can be made between other drills and events to meet several requirements.
2. Documentation is maintained for agency review for five years.

TABLE 3-11:
NPREP REQUIREMENTS DRILL DESCRIPTION

DRILL TYPE	OBJECTIVE	DESCRIPTION	FREQUENCY	EXECUTION	DOCUMENTATION
Qualified Individual Notification Drills	Assure the QI (or Incident Commander) is able to be reached in a spill response emergency. Meeting the QI notification drills requirement is evidence of meeting the preparedness and drill requirements in the NPREP.	Contact must be made by telephone, fax, pager, etc. with the QI. Confirmation must be received. Contact must be documented. This drill is not to verify phone numbers.	Quarterly	Once per quarter, the QI is contacted via the emergency response paging system, and the contact is verified by either phone or visible presence of the QI. Drills of the IMT qualify, as do actual emergency responses. If no drill is planned in a quarter, HSE will request the facility to notify the Incident Commander via pager drill.	Documentation can be via phone or daily log of those triggering the drill, drill or emergency sign-in sheets, change-out notes, etc. Documentation must be kept for 5 years.
Emergency Procedure Drills	The objective of this drill is to verify that vessel or facility personnel are capable of conducting initial actions necessary to mitigate the effects of a spill. Meeting the emergency procedure drills requirement is evidence of meeting the preparedness and drill requirements in the NPREP.	Vessels are not a part of Kuparuk operations and facility emergency procedure drills are optional. Mitigation of spill impact is most closely related to source control in response to a spill in Kuparuk operations. Typical drill scenarios that test this component include over-pressure release, fire, explosion, corrosion, well control loss, etc. Actual events also qualify.	Quarterly	Once per quarter an emergency response drill is conducted or an actual emergency response occurs. If no drill is planned in a quarter, HSE will request Security notify the Incident Commander via pager drill.	Documentation can be via phone or daily log of those triggering the drill, drill or emergency sign-in sheets, change out notes, etc.
Spill Management Team Tabletop Exercises	The objective of this exercise is to drill the management team communication and decision making in managing a spill response. Meeting the QI notification drills requirement is evidence of meeting the preparedness and drill requirements in the NPREP.	Exercise the spill management team in knowledge of the response plan, proper notifications, communication system, ability to access the oil spill response organization (SRT/ACS), coordination of organization/agency personnel with responsibility for spill response, ability to effectively coordinate spill response activity with National Response System infrastructure, and ability to access information in the Area Contingency Plan for location of sensitive areas, resources available within areas, and unique areas, etc.	Annual	Once per year, the IMT is mobilized via the emergency response paging system and an exercise is conducted. If no drill is planned in a quarter, HSE will request the facility notify the Incident Commander via pager drill.	Documentation can be via phone or daily log of those triggering the drill, drill or emergency sign-in sheets, change-out notes, etc. Documentation must be kept for 5 years.

TABLE 3-11 (CONTINUED): NPREP REQUIREMENTS DRILL DESCRIPTION

DRILL TYPE	OBJECTIVE	DESCRIPTION	FREQUENCY	EXECUTION	DOCUMENTATION
Equipment Deployment Drills	The objective of this exercise is to deploy and operate oil spill response equipment identified in the ODPCP. A representative sample or the amount necessary to respond to an average most probable discharge, whichever is less, need be deployed. All equipment must be included in a maintenance program. Meeting the equipment deployment drills requirement is evidence of meeting the preparedness and drill requirements in the NPREP.	Oil spill response equipment shall be deployed semi-annually. Deployment during training counts towards meeting these requirements. Equipment must also be maintained according to manufacturer's specifications and best commercial practices. Deployment via training or drills shall demonstrate the equipment is in good working order. Any dysfunctional equipment shall be repaired within 30 days.	Semi-annually	Twice per year, each type of equipment shall be mobilized, deployed, and operated, or equipment shall be inspected and any necessary maintenance performed.	Initial documentation shall be maintained by the FRT. This documentation shall be provided to HSE quarterly. Documentation shall include dates of deployment, dates of inspection, and/or maintenance, and dates of repairs. Documentation will then be retained and maintained by HSE. Documentation must be kept for 5 years.

Mutual Aid Drill

CPAI participates in an annual MAD exercise. In addition to actively participating in the MAD exercise, federal, state, and local agencies are involved in the development and evaluation of the drill. Every year, equipment is deployed at the MAD exercise per NPREP guidelines. The following are some of the components that may be tested through the MAD exercise:

Organizational Design

- Notifications (includes training on 24-hour notifications and reporting to the National Response Center)
- Staff mobilization
- Ability to operate within the response management system described in the plan

Operational Response

- Discharge control
- Assessment of discharge
- Containment of discharge
- Recovery of spilled material
- Protection of economically and environmentally sensitive areas
- Disposal of recovered product

Response Support

- Communications
- Transportation
- Personnel support
- Equipment maintenance and support
- Procurement
- Documentation

3.10 PROTECTION OF ENVIRONMENTALLY SENSITIVE AREAS [18 AAC 75.425(e)(3)(J)]

Environmentally sensitive areas and areas of public concern include cultural resource sites, Native allotments, and bird nesting areas. Reference materials used to identify these areas include ACS *Technical Manual*, Volume 2, Map Atlas; the *North Slope Subarea Contingency Plan*; and NOAA Environmental Sensitivity Index (ESI) Maps.

The ACS *Technical Manual*, Volume 2, Map Sheets 27 through 55, 68, 69, and 75 through 77 include specific information about priority protection sites and local environmental and cultural sensitivities for areas around Kuparuk facilities and pipelines. In addition, wildlife protection strategies are described in the ACS *Technical Manual*, Volume 1, Tactics W-1 through W-6. The ACS *Technical Manual* is available online at: http://www.alaskacleanseas.org/tech-manual/.

The North Slope Subarea Contingency Plan is a sub-plan of the Unified Plan, Alaska's Area Contingency Plan. It includes specific information on biological and cultural resources on the North Slope for use during initial phases of a spill response. The Subarea Plan includes data on resource sensitivity, habitat types, threatened and endangered species, and has numerous wildlife maps and references to online resources to aid in protection of the environment during a spill response. The Subarea Plan is available online at: http://dec.alaska.gov/spar/perp/plans/scp_ns.htm.

NOAA ESI maps are another important resource for identifying environmentally sensitive areas within the Kuparuk facilities and pipelines operating area. ESI maps help identify locations vulnerable to oil spills, and can help establish protection priorities and identify cleanup strategies. North Slope ESI maps numbers ESI-6 and ESI-7 cover the Kuparuk area and are available online at: http://response.restoration.noaa.gov/esi.

The State of Alaska has established a "Prevention and Emergency Response Subarea Plans Maps" section to their online Alaska State Geo-Spatial Data Clearinghouse. It contains links to subarea plans and their related maps, ESI maps, and other mapping resources such as: nautical and oceanographic charts, land use and management maps, biologically sensitive areas maps, most environmentally sensitive areas maps, and geographic response strategies (GRS) maps. The online Alaska maps clearinghouse is available via the following link:

http://www.asgdc.state.ak.us/maps/cplans/subareas.html#northslope

The effect of seasonal conditions on the sensitivity of the area covered in the plan is detailed in several resources. Volume 2 of the ACS *Technical Manual* includes "Information on Seasonal Sensitivities." The NOAA ESI seasonality tables list each species present in the area. The tables state whether the animals are on any state or federal threatened or endangered species lists and the level of concern, which months the species is present, and the times of various life stages such as nesting or spawning. Both of these sources are publically available using the web links above.

Priority protection sites, environmentally sensitive areas, and areas of public concern that may be impacted during a worst case discharge are described in Section 1.6, Response Strategies. Seasonal conditions during and after proposed drilling are detailed in Section 1.6.13, Spill Response Scenarios. Wildlife protection strategies are described in the ACS *Technical Manual*, Volume 1, Tactics W-1 through W-6, incorporated by reference.

Kuparuk is located in a remote, rural onshore area where the economic base is the oil and gas exploration and production industry, and the government sector. An oil spill from Kuparuk facilities or pipelines would not significantly impact an economically sensitive area; however there is potential to impact local subsistence areas and practices. If historic, prehistoric, or archaeological sites or materials are uncovered during spill recovery operations, the ADNR, Division of Parks and Outdoor Recreation, Office of History and Archaeology is notified.

In the event of a spill, the IMT develops an incident-specific plan that contains strategies to protect environmentally sensitive areas and areas of public concern.

3.10.1 Persistence and Toxicity Effects of Products in the Environment [18 AAC 75.425(e)(3)(J)(ii)]

Crude Oil

Sweet crude oil is amber to black colored liquid. It typically has a sulfurous odor similar to rotten eggs. Crude oil is stable under normal ambient and anticipated conditions of storage and handling. It is extremely flammable as a liquid and vapor. The vapor can cause flash fire. Crude oil exhibited an increase incidence of skin tumors with a chronic application to mouse skin. There is limited evidence of carcinogenicity in animals, and crude oil is not classifiable as to its carcinogenicity in humans. It has not been listed as a carcinogen by the National Toxicology Program (NTP) or by OSHA. Dermal exposure to crude oil during pregnancy resulted in limited evidence of developmental toxicity in laboratory animals. Decreased fetal weight and increased resorptions were noted at maternally toxic doses in laboratory animals. No significant effects on offspring growth or other developmental landmarks were observed postnatally.

Ultra Low Sulfur Diesel Oil

Ultra low sulfur diesel oil is a liquid that is amber to various colors. It may be dyed red. It is combustible as a liquid and vapor. It is harmful if swallowed. It is harmful or fatal if the liquid is aspirated into the lungs. It causes skin irritation. It may cause respiratory tract irritation. Inhalation causes headache, dizziness, drowsiness, and nausea, and may lead to unconsciousness. It is stable under recommended storage and handling conditions.

No component of this product at levels greater than 0.1% is identified as a carcinogen by the American Conference of Governmental Industrial Hygienists or the International Agency for Research on Cancer (IARC.) No component of this product present at levels greater than 0.1% is identified as a carcinogen by the NTP or OSHA. Diesel is toxic to aquatic organisms. It may cause long-term adverse effects in the aquatic environment. Spillages may penetrate the soil causing groundwater contamination. It is not expected to bioaccumulate through food chains in the environment. Spills may form a film on water surfaces causing physical damage to organisms. Oxygen transfer could also be impaired.

No. 1 Diesel

No. 1 Diesel is a crystal-clear liquid with a kerosene-like odor. It is an extremely flammable liquid and vapor. The vapor may cause flash fire or explosion. It may be harmful or fatal if swallowed and may cause lung damage. It contains chemicals that are both human and animal carcinogens. It is toxic to aquatic organisms. Regarding persistence and degradability, it is not readily biodegradable. It may bioaccumulate in aquatic organisms. Regarding mobility in environmental media, it may partition into air, soil, and water.

Lube Oil

Lube oil ranges from a clear and bright to amber liquid in color with a petroleum odor. It is stable under anticipated normal handling and storage conditions. Acute aspirations of large amounts of material may produce serious aspiration pneumonia and can cause irritation and redness to eyes and skin. All of the oils meet the IP-346 criteria of less than 3 percent polyaromatic hydrocarbons and are not considered carcinogens by IARC, NTP, or OSHA.

Extended exposure to high temperature may cause it to decompose. Volatilization is not significant after release of lubricating oil basestocks to the environment due to the very low vapor pressure of the hydrocarbon constituents. In water, lubricating oil basestocks will float and spread at a rate that is viscosity dependent. Water solubilities are very low and dispersion occurs mainly from water movement with adsorption by sediment. In soil, lubricating oil basestocks show little mobility and adsorption is the predominant physical process.

Emulsion Breaker

Emulsion Breaker is a clear, yellow to amber color liquid with a hydrocarbon odor. It is flammable and should not be exposed to heat, sparks, and flames. It is harmful if inhaled, swallowed, or absorbsion through skin and could cause irreversible effects. It may cause eye irritation. Emulsion Breaker containing methanol could cause blindness. Emulsion Breaker containing naphthalene is listed as reasonably anticipated to be carcinogenic by NTP, and listed as IARC Group 2B, possibly carcinogenic to humans. It is toxic to aquatic organisms and may cause long-term adverse effects in the aquatic environment.

Anti-Foam

Anti-foam is a colorless to pink liquid with a hydrocarbon odor. The liquid and vapor is flammable and should not be exposed to heat, sparks, flames, or other ignition sources. It is harmful if swallowed. It is harmful or fatal if the liquid is aspirated into the lungs. It causes skin irritation. It may cause respiratory tract irritation. Inhalation causes headache, dizziness, drowsiness, and nausea, and may lead to unconsciousness. It is suspected of causing cancer and is not listed as a carcinogen by IARC, NTP or OSHA.

Hydrocarbons in Anti-foam are not readily biodegradable but are regarded as inherently biodegradable since their hydrocarbon components can be degraded by microorganisms. On release to water, hydrocarbons will float on the surface and since they are sparingly soluble, the only significant loss is volatilization to air. It is possible that some of the hydrocarbons will be adsorbed on sediment. It is toxic to aquatic organisms and may cause long-term adverse effects in the aquatic environment. Biodegradation in water is a minor loss process and are photodegraded in air.

Corrosion Inhibitor

Corrosion Inhibitor is a brown liquid that is corrosive and highly flammable. Harmful by inhalation and ingestion with possible risk of irreversible effects. It may give off gas, vapor or dust that is very irritating or corrosive to the respiratory system and may cause burns to mouth, throat and stomach if ingested. It is corrosive and can cause burns to the skin and eyes. The naphthalene component is listed as reasonably anticipated to be carcinogenic by NTP, and listed as IARC Group 2B, possibly carcinogenic to humans. It is toxic to aquatic organisms and may cause long-term adverse effects in the aquatic environment.

3.10.2 Prediction of Discharge Movement

Flow from a release is from either a pipeline or a gravel pad to nearby tundra and ponds in summer and to frozen, snow-covered tundra and ponds in winter. See ACS Technical Manual, Volume 1 Tactics T-6 and T-7 for discussion of oil-retention rates of snow and for blowout aerial oil plume distribution, as well as Volume 2 Map Sheets 27 through 55, 68, 69, and 75 through 77 for information on likely surface drainage direction of flow.

3.10.3 Information on Probable Points of Contact

Spilled oil will reach tundra and ponds in summer and frozen, snow- and ice-covered surfaces in winter. Oil trajectories are not expected to affect open water of Gwydyr Bay; but may impact environmentally sensitive areas or areas of public concern including migratory bird nesting locations and terrestrial or marine mammal habitat.

3.11 ADDITIONAL INFORMATION [18 AAC 75.425(e)(3)(K)]

Not applicable.

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PART 4 BEST AVAILABLE TECHNOLOGY [18 AAC 75.425(e)(4)]

This section discusses the best available technology (BAT) requirements contained in 18 AAC 75.425(e)(4)(A), (B), and (C) to address technologies that are not subject to response planning standards (RPS) or performance standards in 18 AAC 75.445(k)(1) and (2). The discussion of each technology covers the requirement to analyze applicable technologies and to provide a justification that the technology is the best available. The spill prevention and response equipment for the Kuparuk Field meet the BAT requirements.

4.1 COMMUNICATIONS [18 AAC 75.425(e)(4)(A)(i)]

The communications system for use in a spill response at Kuparuk is described in the Alaska Clean Seas (ACS) *Technical Manual* Tactic L-11A. Emergency management of a well control incident is described in the internal CPAI *Drilling and Wells Emergency Preparedness and Blowout Contingency Plan*.

4.2 SOURCE CONTROL [18 AAC 75.425(e)(4)(A)(i)]

BAT analysis of source control procedures for applicable operations at Kuparuk are given in Table 4-1 and Table 4-2. Loss of well control (i.e., a blowout) is also discussed in CPAI's well control plan, which addresses procedures for initiating well control, including surface control measures, relief well drilling, and blowout ignition. CPAI will use the services of a professional well control firm if well control is not regained by conventional mechanical means or natural occurrences.

No additional well control technologies are available for a blowout, other than those that will be employed by CPAI personnel and contracted well control services.

4.2.1 Well Source Control

Industry has conducted thorough investigation and research into the use of well capping to regain control of a worst-case well blowout, which is typically defined as the RPS for an exploration or production well. This BAT analysis reviews the techniques and methods to control a deep well blowout that has the potential to release liquid hydrocarbons at the surface. Inherent to this analysis are the assumptions that all primary and secondary levels of well control have failed and that all dynamic and mechanical attempts to regain primary or secondary well control have been ineffective.

The two methods of well control once an incident has escalated to a blowout scenario of the magnitude described above are well capping and relief well drilling (Table 4-1). Industry concludes that well capping constitutes BAT for source control of a well blowout. Historical evidence indicates well capping has greater reliability and application for well control compared to that of relief well drilling. Table 4-1 summarizes well capping as BAT for a well blowout. The rationale for acceptance of well capping as BAT is provided in the following discussion.

Well Capping

As the oil and gas industry continues to advance, well capping techniques have been developed and have proven to be efficient and effective in regaining control of damaged wells and in reducing associated environmental impacts. Significant improvements to well capping techniques and procedures have been developed by a variety of well control specialist companies throughout the world. CPAI has the ability to

mobilize specialized personnel and equipment to a North Slope location within 24 to 48 hours of notification (see Section 1.9).

Well capping is both compatible and feasible with all drilling operations, as the technology is applied at the surface. There are no sensitivities to well types (e.g., extended reach drilling [ERD], horizontal) or location (e.g., remote, island). Well capping techniques have been applied both to onshore and offshore locations, have been historically proven successful in regaining well control in shorter durations, and are preferred over the more time-consuming alternative of drilling a relief well. On the whole, blowouts are typically controlled with more conventional surface control or dynamic kill methods (blowout preventer [BOP] equipment, weighted drilling muds, or cement placement in the well) before capping is attempted or required; drilling relief wells is often a last resort when surface control or kill methods fail and well capping is not feasible.

The Bureau of Safety and Environmental Enforcement and SINTEF Civil and Environmental Engineering (Norway) data indicate well capping technologies provide the shortest duration and most effective option for regaining well control and minimizing environmental impacts once all other control measures have failed. This is shown by the consistent application of well capping instead of relief well drilling in response to well control events and also by the associated short duration to successfully regain well control using well capping as compared to relief well drilling.

Other than the initial cost of the well control equipment currently stationed on the North Slope, maintaining an open contract with Wild Well Control (CPAI's single point of contact for well control, see Section 1.9) is a minimal annual cost. Any additional services required during an actual response would be provided at previously agreed-upon rates.

Well control events where well capping would not be the preferred response involve those in which the potential to release liquid hydrocarbons to the surface is highly unlikely (i.e., shallow gas, compromised surface casing or surface casing cement jobs, broaching or reasonable concern of broaching, inaccessible wellhead and/or casing).

TABLE 4-1:
BEST AVAILABLE TECHNOLOGY ANALYSIS
WELL BLOWOUT SOURCE CONTROL

BAT EVALUATION CRITERIA	EXISTING METHOD: WELL CAPPING	ALTERNATE METHOD: RELIEF WELL DRILLING
AVAILABILITY: Whether technology is best in use in other similar situations or is available for use by applicant	Well capping is in use globally. Fit-for-purpose well capping and well control equipment is located on the North Slope. Additional equipment can be on location within 24-48 hours.	Relief well drilling equipment (rigs, downhole tools, etc.) is available.
TRANSFERABILITY: Whether each technology is transferable to applicant's operations	Equipment is currently available on the North Slope or on retainer via Wild Well Control contract.	Multiple drilling rigs are currently under contract on the North Slope.
EFFECTIVENESS: Whether there is a reasonable expectation each technology will provide increased spill prevention or other environmental benefits	Numerous global companies provide successful applications of well capping. After natural bridging and conventional methods (blowout preventer [BOP], mud, cementing, equipment repairs), well capping is the most frequent blowout control measure. Application of well capping provides the best opportunity for minimizing pollution impacts.	Rare successful application of relief well drilling has been documented in industry. Industry data suggest a very small percentage of blowouts are successfully controlled with technique. Relief well drilling as compared to well control from dynamic and mechanical methods is the longest pollution mitigation measure possible. Relief wells may be the preferred response method in some well control events (shallow gas, compromised surface casing or surface casing cementing, broaching, etc.), but these are events highly unlikely to result in the release of liquid hydrocarbons.
COST: The cost to the applicant of achieving BAT, including consideration of that cost relative to the remaining years of service of the technology in use by the applicant	Fit-for-purpose equipment is already owned and/or under long-term contract. Well capping requires the maintenance of open-end contracts with trained specialists to implement well control/capping operations.	Time and cost of permitting, location construction, well planning, and executing relief wells is estimated at 2 to 3 times the cost of well capping, excluding any lost production.
AGE AND CONDITION: The age and condition of technology in use by the applicant	Well capping technology has made improvements since its frequent application during the Iraq-Kuwait conflict in the early 1990s. Firefighting equipment is in place on the North Slope.	Relief well drilling technology is similar to current methods used to drill/complete North Slope wells. It is potentially sensitive to blowout well types (extended reach drilling [ERD]).
COMPATIBILITY: Whether each technology is compat ble with existing operations and technologies in use by the applicant	Technology is compatible and applied at surface (no sensitivity to well type).	Technology is compat ble, though potentially sensitive to blowout well types (ERD, remote locations, etc.). Survey uncertainty on high departure wells may result in problems intersecting target wel bore.

TABLE 4-1 (CONTINUED):
BEST AVAILABLE TECHNOLOGY ANALYSIS
WELL BLOWOUT SOURCE CONTROL

BAT EVALUATION CRITERIA	EXISTING METHOD: WELL CAPPING	ALTERNATE METHOD: RELIEF WELL DRILLING
FEASIBILITY: The practical feasibility of each technology in terms of engineering and other operational aspects	Method is feas ble with all drilling operations. Applied at surface – no sensitivities to well type (ERD, remote locations, etc.). Prior proven success in offshore environments. Demonstrated success in historical well control efforts.	Method is feasible contingent on geographical access near area of blowout. Lack of year-round access to some locations (offshore) limits application. There is little evidence of successful application of relief well drilling as the primary mitigation measure of control. Relief wells may be the preferred response method in some well control events (shallow gas, compromised surf casing or surf casing cementing, broaching, etc.), but these are events highly unlikely to result in the release of liquid hydrocarbons.
ENVIRONMENTAL IMPACTS: Whether other environmental impacts of each technology, such as air, land, water pollution, and energy requirements, offset any anticipated environmental benefits	Technology provides the best proven opportunity to quickly reduce environmental impacts. Estimated duration of 18-30 days is significantly less than conventional alternative technologies.	Technology provides additional exposure and environmental risks during application (additional well control problems). Technology application may be seasonally limited, leading to durations of 60-180 days. Relief wells may require additional gravel placement and mobilization or demobilization pressures on the local environment. Drilling a relief well is accompanied by the additional risk of a second well control event.

Relief Well

The lead-time involved in relocating a rig to a surface location and drilling a relief well necessitates planning early in the incident. Due to the long lead times associated with drilling a relief well, the incident-specific relief well plan may be initiated concurrently with the implementation of surface control methods. If surface control methods fail, the incident-specific relief well plans are fully implemented. It should be recognized that a relief well is generally considered as a last resort to regain control of a blowout. It is far more common to kill the well with surface kill techniques or for the well to cease flowing due to depletion or the formation of a natural bridge in the wellbore.

Relief well drilling technology is compatible with North Slope drilling operations, although it may be sensitive to both the well location and well type. Multiple drilling rigs that are capable of drilling a relief well are under contract on the North Slope. Downhole and surface equipment (tubulars, wellheads, etc.) to support relief well drilling operations are also available. Rig-sharing agreements are in place between CPAI and BP, to facilitate optimum response times and to ensure rig availability in the event of a blowout.

Relief well drilling has been attempted only once as a mitigation measure to control a blowout on the North Slope. This was the ARCO Cirque gas well blowout in 1992, where well control was regained by a combination of well capping techniques and an assist from natural bridging. Relief well drilling is similar to current methods used to drill and complete North Slope wells today, and advances in directional drilling technology that allow for more precise wellbore placement, increase the likelihood of the success of a relief well. However, relief well attempts are thus more sensitive to blowout well location and/or blowout well type. For extended reach wells, or remote locations with limited access, relief well drilling is both logistically challenging and time consuming, thereby adding an undesired increase to the overall environmental impact (volume spilled) from the blowout.

Well control events where the preferred response methods would be relief well drilling involve situations in which the potential to release liquid hydrocarbons to the surface is highly unlikely (i.e., shallow gas, compromised surface casing or surface casing cement jobs, broaching or reasonable concern of broaching, inaccessible wellhead and/or casing).

4.2.2 Crude Oil Transmission Pipeline Source Control

Table 4-2 is the source control BAT review for crude oil transmission pipelines. Both automatic and manual ball valves, currently used as crude oil transmission pipeline source control at Kuparuk, are considered BAT for the following reasons:

- The system is highly reliable, time-tested, and commonly used throughout the oil industry.
- Automatic ball valves can be an advantage in certain circumstances because they are not dependent on human intervention for source control.
- Manual ball valves, as used on the Kuparuk Pipeline, are preferred over automatic valves because of the need to integrate human (operator) intervention into any decision to close these two pipelines.
- Ball valves are a quicker means of source control than gate valves.
- Ball valves are an effective stand-alone system.
- The system provides a bi-directional source control on the pipeline, as opposed to check valves.
- Automatic valves can be manually closed if necessary – an additional contingency.

Automatic and manual valves are currently installed. There is no additional cost to implement this technology.

TABLE 4-2:
BEST AVAILABLE TECHNOLOGY ANALYSIS
CRUDE OIL TRANSMISSION PIPELINE SOURCE CONTROL

BAT EVALUATION CRITERIA
AVAILABILITY: Whether technology is best in use in other similar situations or is available for use by applicant
TRANSFERABILITY: Whether each technology is transferable to applicant's operations
EFFECTIVENESS: Whether there is a reasonable expectation each technology will provide increased spill prevention or other environmental benefits

TABLE 4-2 (CONTINUED):
BEST AVAILABLE TECHNOLOGY ANALYSIS
CRUDE OIL TRANSMISSION PIPELINE SOURCE CONTROL

BAT EVALUATION CRITERIA
COST: The cost to the applicant of achieving BAT, including consideration of that cost relative to the remaining years of service of the technology is use by the applicant.
AGE AND CONDITION: The age and condition of technology in use by the applicant
COMPATIBILITY: Whether each technology is compatible with existing operations and technologies in use by the applicant
FEASIBILITY: The practical feasibility of each technology in terms of engineering and other operational aspects

TABLE 4-2 (CONTINUED):
BEST AVAILABLE TECHNOLOGY ANALYSIS
CRUDE OIL TRANSMISSION PIPELINE SOURCE CONTROL

BAT EVALUATION CRITERIA
ENVIRONMENTAL IMPACTS: Whether other environmental impacts of each technology, such as air, land, water pollution, and energy requirements, offset any anticipated environmental benefits

4.2.3 Tank Source Control

The BAT review for source control from a tank focuses on the technology used to stop the inflow of product into the ruptured tank. This tank source control BAT review is provided in Table 4-3. Both manual and automatic valves are used on regulated oil storage tanks at Kuparuk. Automatic valves are provided on process and large storage tanks that may be subject to continuous filling or draining as part of the production process. Automatic valves are considered BAT in these instances because they provide the most effective means to stop the flow of oil into tanks with levels that constantly change. However, the facility operator also has the ability to manually close tank valves if low- or high-level alarms indicate a potential source control problem. Isolation of the tank and removal of contents by vacuum truck also may be used by operations for source control.

Manual valves are used on regulated oil storage tanks that are filled infrequently. These tanks are subject to CPAI tank-filling standard operating procedures requiring the presence of an operator during all filling operations. Tank spill root-cause analysis by CPAI indicates that source control for filling tanks is best achieved by the on-site presence of an operator who can immediately stop a tank-filling operation if a potential source control problem occurs. For this reason, manual valves are considered BAT for these tanks.

Examples of how these source control procedures would be implemented are located in Section 1.6.3 as part of the pipeline spill, tank failure, and well control response planning scenarios.

4.3 TRAJECTORY ANALYSES AND FORECASTS [18 AAC 75.425(e)(4)(A)(i)]

BAT for trajectory analyses and forecasts are described in the ACS *Technical Manual*.

4.4 WILDLIFE CAPTURE, TREATMENT, AND RELEASE PROGRAMS [18 AAC 75.425(e)(4)(A)(i)]

Wildlife capture, treatment, and release programs are described in the ACS *Technical Manual* Tactic L-11C.

4.5 CATHODIC PROTECTION FOR FIELD-CONSTRUCTED OIL STORAGE TANKS [18 AAC 75.425(e)(4)(A)(ii)]

This regulation references cathodic protection requirements for new installations of field-constructed, aboveground oil storage tanks (i.e., oil storage tanks constructed, installed, or placed into service after May 14, 1992). As such, this regulation is not applicable to field-constructed, aboveground oil storage tanks at Kuparuk installed prior to the effective date of the regulation. Installation of a cathodic corrosion protection system to the standards of American Petroleum Institute (API) Standard 651 meets the performance requirements of 18 AAC 75.065(h)(2)(i)(3) and is therefore BAT.

Appendix B lists the applicable field-constructed, aboveground oil storage tanks at Kuparuk and whether cathodic protection is provided. The tanks subject to bottom corrosion from potential contact with the soil have cathodic protection. The cathodic protection systems installed on the on-grade tanks at Kuparuk are in accordance with API 651, “Cathodic Protection of Above-grade Petroleum Storage Tanks.”

TABLE 4-3:
BEST AVAILABLE TECHNOLOGY ANALYSIS
TANK SOURCE CONTROL

BAT EVALUATION CRITERIA
AVAILABILITY: Whether technology is best in use in other similar situations or is available for use by applicant
TRANSFERABILITY: Whether each technology is transferable to applicant's operations
EFFECTIVENESS: Whether there is a reasonable expectation each technology will provide increased spill prevention or other environmental benefits
COST: The cost to the applicant of achieving BAT, including consideration of that cost relative to the remaining years of service of the technology, is used by the applicant
AGE AND CONDITION: The age and condition of technology in use by the applicant
COMPATIBILITY: Whether each technology is compatible with existing operations and technologies in use by the applicant
FEASIBILITY: The practical feas bility of each technology in terms of engineering and other operational aspects
ENVIRONMENTAL IMPACTS: Whether other environmental impacts of each technology, such as air, land, water pollution, and energy requirements, offset any anticipated environmental benefits

4.6 LEAK DETECTION SYSTEM FOR FIELD-CONSTRUCTED OIL STORAGE TANKS [18 AAC 75.425(e)(4)(A)(ii)]

This regulation references leak detection requirements for new installations of field-constructed, aboveground oil storage tanks (i.e., oil storage tanks constructed, installed, or placed into service after May 14, 1992). As such, this regulation is not applicable to field-constructed oil storage tanks at Kuparuk placed in service prior to the effective date of the regulation. Field-constructed, aboveground oil storage tanks at Kuparuk placed in service prior to May 14, 1992 have lined secondary containment in accordance with 18 AAC 75.065(h)(1)(A).

Non-elevated oil storage tanks at Kuparuk, regardless of their construction date, use a combination of methods for leak detection. The predominant leak detection system is lined secondary containment. Each tank's secondary containment is visually inspected for the presence of free product during each 12-hour shift by facility personnel, weather permitting (see Section 2.5). In addition, these tanks are also equipped with a sensitive gauging system that indicates fluid level in the tanks. These fluid levels are monitored in the facility control room for indications of abnormal operation that might signal a leak in the tank. Tanks are visually inspected for leaks in accordance with the requirements of 18 AAC 75.065.

TABLE 4-4:
BEST AVAILABLE TECHNOLOGY ANALYSIS
TANK LEAK DETECTION

BAT EVALUATION CRITERIA
AVAILABILITY: Whether technology is best in use in other similar situations or is available for use by applicant
TRANSFERABILITY: Whether each technology is transferable to applicant's operations
EFFECTIVENESS: Whether there is a reasonable expectation each technology will provide increased spill prevention or other environmental benefits
COST: The cost to the applicant of achieving BAT, including consideration of that cost relative to the remaining years of service of the technology, is used by the applicant
AGE AND CONDITION: The age and condition of technology in use by the applicant
COMPATIBILITY: Whether each technology is compatible with existing operations and technologies in use by the applicant
FEASIBILITY: The practical feasibility of each technology in terms of engineering and other operational aspects
ENVIRONMENTAL IMPACTS: Whether other environmental impacts of each technology, such as air, land, water pollution, and energy requirements, offset any anticipated environmental benefits

4.7 OTHER PREVENTION SYSTEMS APPROVED BY ADEC UNDER 18 AAC 75.065(h)(1)(D)

This section of the regulations is not applicable to Kuparuk.

4.8 LIQUID LEVEL DETERMINATION [18 AAC 75.425(e)(4)(A)(ii)]

ADEC-regulated stationary bulk storage tanks in Kuparuk have either high-level alarms or constant-level indicators that show remotely in the associated facility control room or on the tank itself.

It should be noted that the BAT for tank liquid level determination at Kuparuk is a function of the liquid in the tank and the operational history of the level technology used in that tank. Table 4-5 lists technologies that are presently used in regulated stationary tanks at Kuparuk. The liquid level determination technology used on these tanks is continually evaluated for its effectiveness and maintenance requirements against newer technologies that could provide more accurate; cost-effective service may be evaluated, as needed. This continual technology assessment has resulted in the assortment of liquid level indicators used at Kuparuk.

For regulated portable tanks equal to or greater than 10,000 gallons without liquid level instrumentation, tank liquid levels are measured to determine the required volume prior to any fuel transfers. Fluid transfers follow the inspection and fluid transfer procedures noted in Section 3.1.2. Tank liquid levels will be checked primarily by visual means prior to filling (e.g., by direct observation through the hatch using a flashlight). Visual observation may be more accurate and reliable than other “low tech” devices such as sight glasses, float gauges, or tank strapping, due to the tendency for these devices to fail under freezing conditions (Table 4-6). Best management practices indicate two operators be present and in direct line of sight of each other, or at least in constant communication via radio or hand signal, for the duration of the fuel transfer, with one person having the ability to shut down the fuel transfer in the event of an emergency. Tank liquid levels will be monitored throughout the duration of the filling process. This method is as good as or better than the five alternative methods for regulated portable tanks presented in Table 4-6, and it provides the most reliable, feasible, and cost-effective alternative to those methods.

In some cases, additional liquid level determination devices may be applied to provide a secondary (redundant) means of assessing fluid levels prior to, during, and after transfer operations. Note that mechanical or visual means are preferable to electronic devices, as they do not constitute potential ignition sources and obviate the need for extensive electrical conduit runs. Mechanical devices such as float-type level indicators are generally reliable and accurate, as long as the subject tank is of sufficient size to preclude turbulence during transfer operations (e.g., greater than 10,000 gallons) and is situated in a stable environment (i.e., free of influences such as vibrations or jolts that may jam the float). The float devices are relatively inexpensive and easily installed. Accordingly, mechanical float-type devices must be installed when tanks are located in a structurally stable environment to provide a redundant means of fluid level determination.

TABLE 4-5:
BEST AVAILABLE TECHNOLOGY ANALYSIS
STATIONARY TANK LIQUID LEVEL DETERMINATION SYSTEM

BAT EVALUATION CRITERIA
AVAILABILITY: Whether technology is best in use in other similar situations or is available for use by applicant.
TRANSFERABILITY: Whether each technology is transferable to applicant's operations.
EFFECTIVENESS: Whether there is a reasonable expectation each technology will provide increased spill prevention or other environmental benefits

TABLE 4-5 (CONTINUED):
BEST AVAILABLE TECHNOLOGY ANALYSIS
STATIONARY TANK LIQUID LEVEL DETERMINATION SYSTEM

BAT EVALUATION CRITERIA	
COST: The cost to the applicant of achieving BAT, including consideration of that cost relative to the remaining years of service of the technology is use by the applicant.	
AGE AND CONDITION: The age and condition of technology in use by the applicant	
COMPATIBILITY: Whether each technology is compatible with existing operations and technologies in use by the applicant	
FEASIBILITY: The practical feasibility of each technology in terms of engineering and other operational aspects	

TABLE 4-5 (CONTINUED):
BEST AVAILABLE TECHNOLOGY ANALYSIS
STATIONARY TANK LIQUID LEVEL DETERMINATION SYSTEM

BAT EVALUATION CRITERIA			EXISTING				EXISTING METHOD:
ENVIRONMENTAL IMPACTS: Whether other environmental impacts of each technology, such as air, land, water pollution, and energy requirements, offset any anticipated environmental benefits							

TABLE 4-6:
BEST AVAILABLE TECHNOLOGY ANALYSIS
TANK LIQUID LEVEL DETERMINATION SYSTEM

BAT EVALUATION CRITERIA
AVAILABILITY: Whether technology is best in use in other similar situations or is available for use by applicant
TRANSFERABILITY: Whether each technology is transferable to applicant's operations
EFFECTIVENESS: Whether there is a reasonable expectation each technology will provide increased spill prevention or other environmental benefits

TABLE 4-6 (CONTINUED):
BEST AVAILABLE TECHNOLOGY ANALYSIS
TANK LIQUID LEVEL DETERMINATION SYSTEM

BAT EVALUATION CRITERIA
COST: The cost to the applicant of achieving best available technology (BAT), including consideration of that cost relative to the remaining years of service of the technology in use by the applicant.
AGE AND CONDITION: The age and condition of technology in use by the applicant
COMPATIBILITY: Whether each technology is compat ble with existing operations and technologies in use by the applicant

TABLE 4-6 (CONTINUED):
BEST AVAILABLE TECHNOLOGY ANALYSIS
TANK LIQUID LEVEL DETERMINATION SYSTEM

BAT EVALUATION CRITERIA
FEASIBILITY: The practical feas bility of each technology in terms of engineering and other operational aspects
ENVIRONMENTAL IMPACTS: Whether other environmental impacts of each technology, such as air, land, water pollution, and energy requirements offset any anticipated environmental benefits

Note 1 – Engineering Analysis of Automated Leak Detection/Liquid Level Measurement Devices

Currently, five types of liquid level/leak detection measurement devices are used in fuel storage tank applications: pressure transducer, electronic float, actuated, sight glass, and tank strapping. Electronic types typically employ ultrasonic or microwave frequency transducers. In the context of small, portable and temporary tanks, the effective utility of the devices is greatly compromised as follows.

Small portable tanks that are mounted on motor vehicles are subject to vibrations and jolts from operation on unimproved roads and wind gusts. These conditions result in liquid level measurements that fluctuate constantly, particularly for the more sensitive devices such as microwave frequency. Float-type devices are particularly prone to

TABLE 4-6 (CONTINUED):
BEST AVAILABLE TECHNOLOGY ANALYSIS
TANK LIQUID LEVEL DETERMINATION SYSTEM

damage under these conditions. While it is possible to tune associated controller outputs to mitigate the effects of vibration and jolts, such a state of tune would significantly decrease their accuracy and response times in terms of liquid level measurement and preclude their use as leak detection devices.

Small, temporary tanks located on gravel pads, or on the rig itself, would be subject to similar vibrations and jolts. Accordingly, application of these devices to small, portable and temporary tanks results in an error in liquid level measurement and in frequent false alarms in high level and leak detection contexts. Handling during loading, transportation, and unloading may also result in physical damage to the level determination device, such as sight glass devices, or electronic components contained therein (as applicable).

In addition, should these devices be used to control automatic shutoff valves or pump shutoff relays, unanticipated valve closures or pump shutdowns may occur, with potential oil spill consequences. The inability of these devices to function accurately and reliably on small, portable and temporary tanks, and the significant cost of custom construction, installation, and maintenance, preclude their use. Note that flow test tank fluids are typically composed of oil, water, associated emulsions, and suspended solids. The multiphase nature of these fluids adversely impacts the accuracy and reliability displayed by a variety of level determination devices. For example, microwave frequency device accuracy is compromised by variations in liquid dielectric constant and electrical conductivity; accordingly, application in multiphase liquid contexts is contradictory. Alternatively, ultrasonic devices require contact with the process fluid; solids buildup or emulsion adherence to the sensor will result in decreased accuracy and the need for frequent maintenance.

Mechanical devices, such as float-actuated and tank strapping devices, are also subject to greatly reduced accuracy and reliability resulting from solids content. These solids facilitate float “sticking” and “jamming.” In addition, extreme cold weather results in pulleys that may not roll freely or that freeze up altogether, or associated cable systems that become inflexible. Any one or more of these effects will render the device unreliable in terms of accurate level determination. Spill data indicate that approximately 4 percent of the spills at Kuparuk on the North Slope are due to malfunctioning of tank level gauges.

In summary, the application of additional (i.e., in addition to direct observation in concert with manual gauging) liquid level determination devices to portable and temporary tanks in an arctic (frigid) environment, is not desirable for the following reasons:

- Significant potential for physical damage, or damage to associated electronic components, as a result of loading, unloading, or transportation
- Requirement for power source – a potential source of ignition
- Need for frequent maintenance
- Lack of warranty
- Decreased accuracy
- Decreased reliability
- Significant cost (e.g., device, power, installation, maintenance, and replacement)

4.9 MAINTENANCE PROCEDURES FOR BURIED STEEL FACILITY OIL PIPING [18 AAC 75.080(b)]

A Below-Grade Piping (BGP) program with annual reporting criteria was approved by ADEC in a letter dated October 26, 1998 (see Section 2.6). Annual reports to ADEC were generated in 1998, 1999, and 2000, and continue. Pursuant to a memorandum written by ARCO Alaska, Inc. (AAI) to Robert Watkins of ADEC, dated April 18, 1999, the following agreement was reached: “Because the BGP plans are susceptible to frequent change, AAI and ADEC have agreed not to include them as attachments to the AAI C-Plans.”

Section 2.6 includes the October 26, 1998 approval letter from ADEC for this corrosion program.

Subsequently, with the establishment of the North Slope Charter Agreement between ADEC, BP, and CPAI, an agreement was reached to document future BGP plans in the annual “Commitment to Corrosion” reports, which are supplied to ADEC by CPAI and BP. This agreement was documented on page 9 of Coffman Engineers’ “Technical Analysis of ConocoPhillips Alaska, Inc. – Commitment to Corrosion Monitoring for Greater Kuparuk Area & Alpine.”

4.10 PROTECTIVE COATINGS AND CATHODIC PROTECTION FOR FACILITY PIPING [18 AAC 75.425(e)(4)(A)(ii)]

Regulation at 18 AAC 75.080(e)(2)(A) applies to new installations of buried steel piping containing oil and placed in service after December 30, 2008. The majority of the buried piping in Kuparuk falls into the category of “existing piping” because it has been installed for a number of years. Any buried steel piping installed between May 14, 1992 and December 30, 2008, will be installed and protected according to 18 AAC 75.080(d).

Below-grade sections of pipelines, such as piping in casings at road crossings, are installed with external corrosion control coatings. Corrosion protection coatings effectively provide a direct barrier to water in this application. Fusion-bonded epoxy (FBE) and other protective coatings, depending on the application, provide the best corrosion protection for the North Slope operating environment. BGP is not normally in contact with soil at the road crossings at post-1992 drill sites; therefore, cathodic protection of these pipelines would not be appropriate based on local soil conditions pursuant to 18 AAC 75.080(b)(1)(A). See Table 4-7 for BAT comparison for external coatings for BGP.

4.11 CRUDE OIL TRANSMISSION PIPELINE LEAK DETECTION [18 AAC 75.055(a)]

TABLE 4-7:
BEST AVAILABLE TECHNOLOGY ANALYSIS
EXTERNAL COATINGS FOR BELOW-GRADE SECTIONS OF PIPELINES

BAT EVALUATION CRITERIA	EXISTING METHOD: FUSION-BONDED EPOXY	ALTERNATE METHOD: COAL TAR OR EXTRUDED POLYETHYLENES	ALTERNATE METHOD: PAINTS (ENAMEL OR ZINC OXIDE PRIMER) AND OTHER COATING SYSTEMS
AVAILABILITY: Whether technology is best in use in other similar situations or is available for use by applicant	Technology is available and is used.	Technology is available and is used. Not available in existing coating mills in Alaska.	Technology is available and is used.
TRANSFERABILITY: Whether each technology is transferable to applicant's operations	Currently installed.	Can be used.	Currently installed.
EFFECTIVENESS: Whether there is a reasonable expectation each technology will provide increased spill prevention or other environmental benefits	Effective means to provide coverage over the entire length of the below-grade section of pipeline. In addition, this product can be covered with concrete to provide additional physical protection at the rivers where the pipe might be pulled in during installation.	Would likely not be as effective as FBE. Likely to be damaged in shipment to the site at low temperatures and is not reliable within the pipeline operating temperatures.	Does not provide the required protection that is required for buried pipe that comes in contact with soils.
COST: The cost to the applicant of achieving BAT, including consideration of that cost relative to the remaining years of service of the technology is use by the applicant	Approximate cost is $100,000 to coat the below-grade sections of the pipeline.	Approximate cost is $100,000 to coat the below-grade sections of the pipeline.	Cost is approximately $75,000.
AGE AND CONDITION: The age and condition of technology in use by the applicant	Method is current.	Method is current.	Method is current.
COMPATIBILITY: Whether each technology is compatible with existing operations and technologies in use by the applicant	Compatible with coating systems and installation method. It is compatible with concrete coating that was installed over the FBE to provide mechanical protection when the pipe is pulled in.	Not compatible with cold temperature environment that the pipe will be installed in.	Not compat ble with concrete coating that will be installed over the line to provide mechanical protection of the pipe.
FEASIBILITY: The practical feasibility of each technology in terms of engineering and other operational aspects	Method is feasible and is commonly used.	Not feasible to use because it will not provide the level of protection required based on the period of the year the line will be installed (cold temperature weather) and the operating temperature of the pipeline.	Not appropriate coating for a buried pipeline.

TABLE 4-7 (CONTINUED):
BEST AVAILABLE TECHNOLOGY ANALYSIS
EXTERNAL COATINGS FOR BELOW-GRADE SECTIONS OF PIPELINES

BAT EVALUATION CRITERIA	EXISTING METHOD: FUSION-BONDED EPOXY	ALTERNATE METHOD: COAL TAR OR EXTRUDED POLYETHYLENES	ALTERNATE METHOD: PAINTS (ENAMEL OR ZINC OXIDE PRIMER) AND OTHER COATING SYSTEMS
ENVIRONMENTAL IMPACTS: Whether other environmental impacts of each technology, such as air, land, water pollution, and energy requirements, offset any anticipated environmental benefits	No additional environmental impacts.	Coal tar coatings present possible environmental concerns when coating has to be removed for maintenance or field installation.	No additional environmental impacts. Buried in the same ditch as the pipeline.

TABLE 4-8:
LEAK DETECTION IN CRUDE OIL TRANSMISSION PIPELINE

BAT EVALUATION CRITERIA
AVAILABILITY: Whether technology is best in use in other similar situations or is available for use by applicant

TABLE 4-8 (CONTINUED):
LEAK DETECTION IN CRUDE OIL TRANSMISSION PIPELINE

BAT EVALUATION CRITERIA
TRANSFERABILITY: Whether each technology is transferable to applicant's operations

TABLE 4-8 (CONTINUED):
LEAK DETECTION IN CRUDE OIL TRANSMISSION PIPELINE

BAT EVALUATION CRITERIA	
EFFECTIVENESS: Whether there is a reasonable expectation each technology will provide increased spill prevention or other environmental benefits	
COST: The cost to the applican of achieving BAT, including consideration of that cost relative to the remaining years of service of the technology is use by the applicant.	
AGE AND CONDITION The age and condition o technology in use by th applicant	

TABLE 4-8 (CONTINUED):
LEAK DETECTION IN CRUDE OIL TRANSMISSION PIPELINE

BAT EVALUATION CRITERIA	
COMPATIBILITY: Whether each technology is compatible with existing operations and technologies in use by the applicant	
FEASIBILITY: The practical feasibility of each technology in terms of engineering and other operational aspects	
ENVIRONMENTAL IMPACTS: Whether other environmental impacts of each technology, such as air, land, water pollution, and energy requirements, offset any anticipated environmental benefits	

PART 5 RESPONSE PLANNING STANDARD [18 AAC 75.425(e)(5)]

For purposes of this plan, the applicable response planning standard (RPS) volumes are as follows.

5.1 PRODUCTION WELL BLOWOUT [18 AAC 75.434]

The production numbers below were obtained from the Alaska Oil and Gas Conservation Commission and are publically available data.

At Kuparuk during 2011, the highest annual volume was produced by well 1J-166. The annual production at well 1J-166 was 524,545 barrels. The average daily production was 1,437 barrels of oil per day (bopd), which is rounded to 1,500 bopd. This well produces heavy oil and uses assisted lift methods (gas lift); therefore, the corresponding RPS volume is three times the daily production rate (3 days x 1,500 bopd), or 4,500 barrels.

Alternatively, CPAI conducted analysis on well 2A-15, which is classified by the Alaska Oil and Gas Conservation Commission as a “gas lift” production well because gas lift equipment was installed downhole to allow gas lift assistance to produce the well in the future, if necessary. However, this well is currently capable of flowing without gas lift assistance due to existing high reservoir pressure and formation gas volume. The well is representative of a typical production well in the Kuparuk field. The production from August 2009 to August 2012 at well 2A-15 was 312,583 barrels. The average daily production rate was 540 bopd. Because this well is capable of flowing without gas lift assistance, the most appropriate RPS volume for well 2A-15 is 15 times the daily production rate (15 days x 540 bopd), or 8,100 barrels.

Consequently, the highest (most conservative) RPS volume for Kuparuk is 8,100 barrels at well 2A-15.

5.2 KUPARUK PIPELINE SPILL TO KUPARUK RIVER [18 AAC 75.436]

(b) (7)(F), (b) (3)

APPENDIX A:

FACILITY DIAGRAMS

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ConocoPhillips
Alaska, Inc.

Kuparuk Field
General Layout
Figure A-1

Jan. 2003	NTS	03010855A00

Pipeline Route Vicinity Map
Figure A-2

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KUPARUK RIVER UNIT
CPF 1
Site Detail

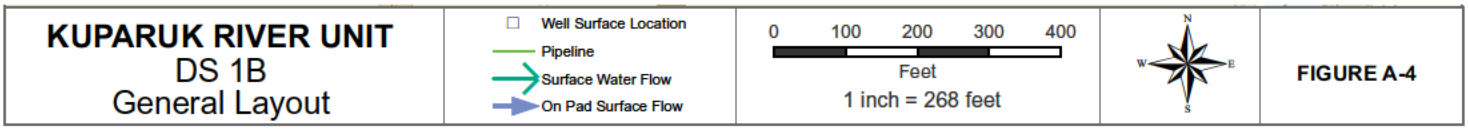
Well Surface Location
Pipeline
Surface Water Flow
On Pad Surface Flow

0 45 90 180 270 360
Feet
1 inch = 249 feet

N
W E
S

FIGURE A-3

March 2013, Rev. 0



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KUPARUK RIVER UNIT
CPF 2
Site Detail

Well Surface Location
Pipeline
Surface Water Flow
On Pad Surface Flow

0 25 50 100 150 200
Feet
1 inch = 162 feet

N
W E
S

FIGURE A-6

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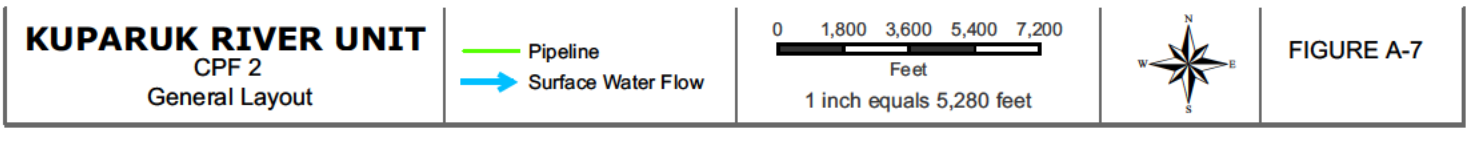

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KUPARUK RIVER UNIT
CPF 3
Site Detail

Well Surface Location
Pipeline
Surface Water Flow
On Pad Surface Flow

0 25 50 100 150 200
Feet
1 inch = 150 feet

N
W E
S

FIGURE A-8

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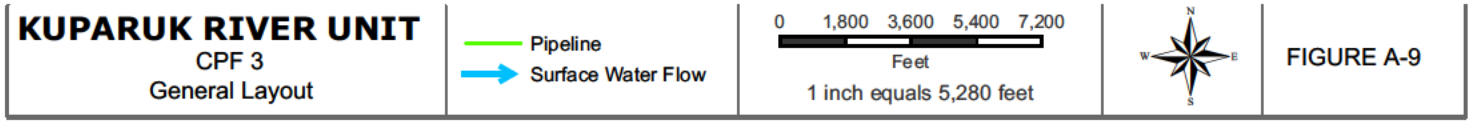
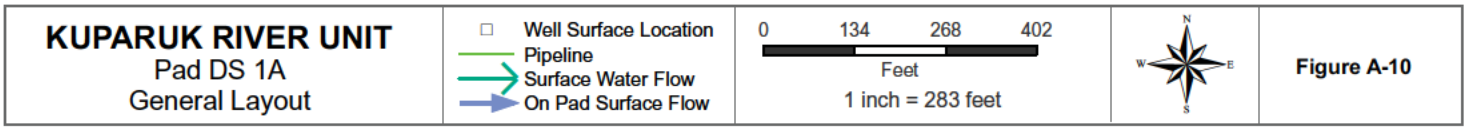

KUPARUK RIVER UNIT
CPF 3
General Layout
Pipeline
Surface Water Flow
0 1,800 3,600 5,400 7,200
Feet
1 inch equals 5,280 feet
N
W
E
S
FIGURE A-9



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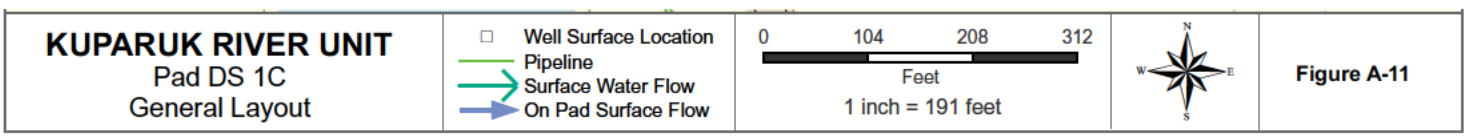

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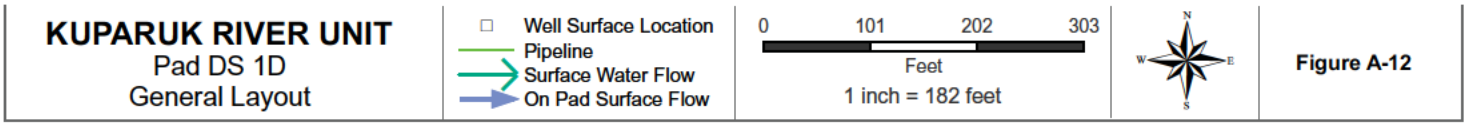

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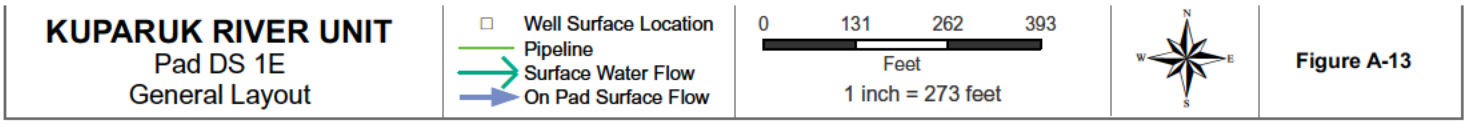

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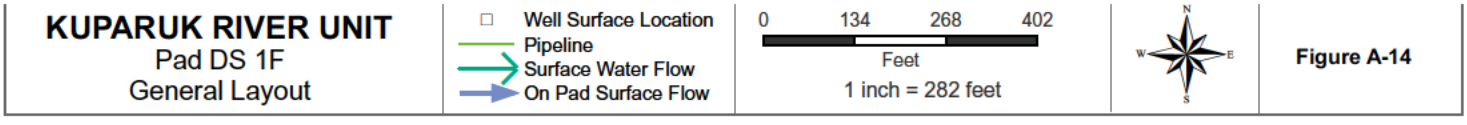

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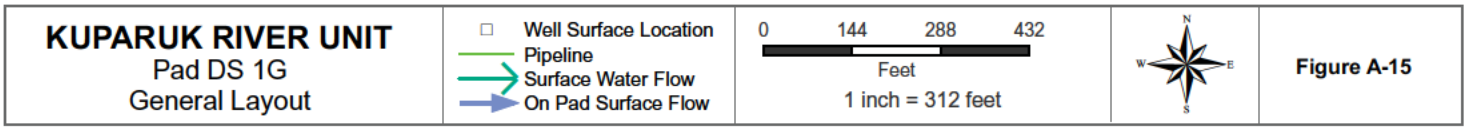

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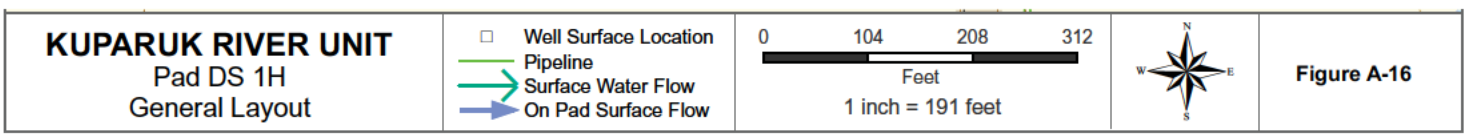

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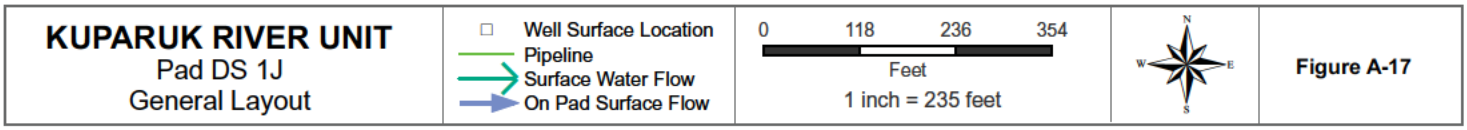

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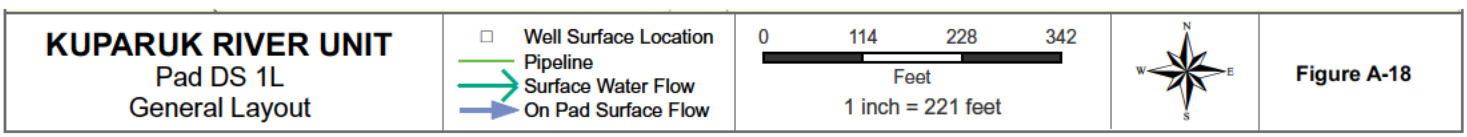

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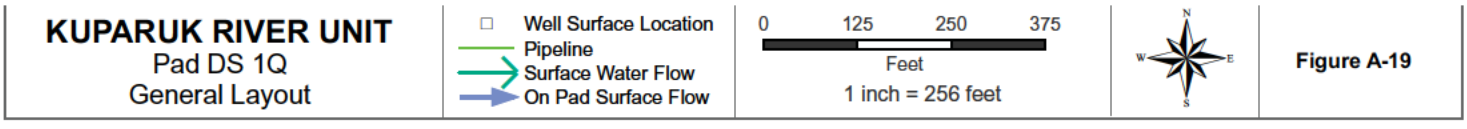

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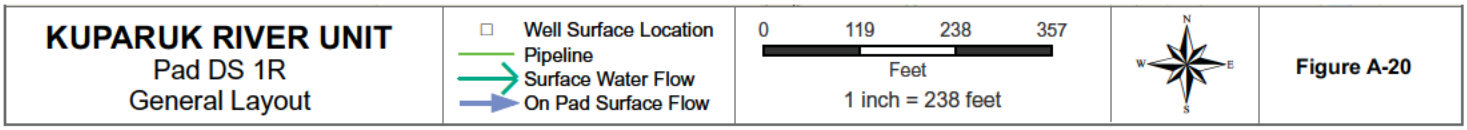

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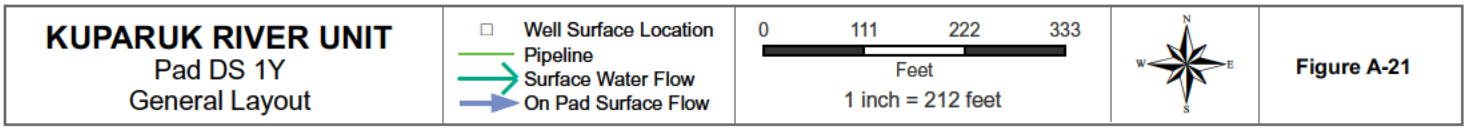

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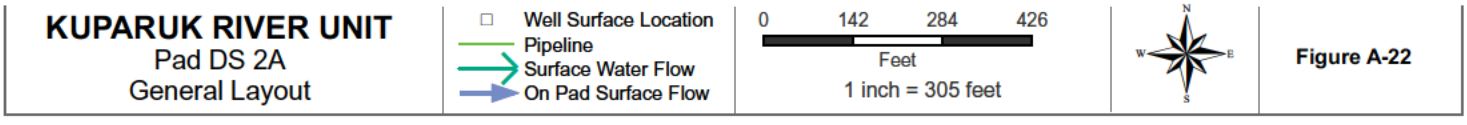

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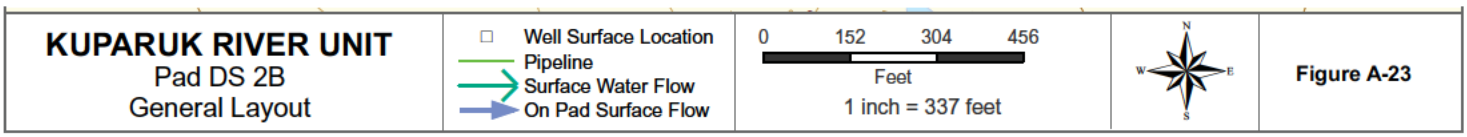

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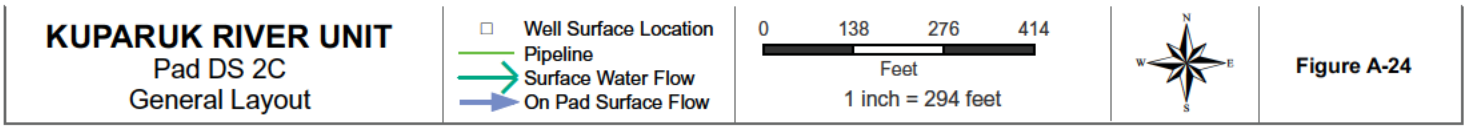

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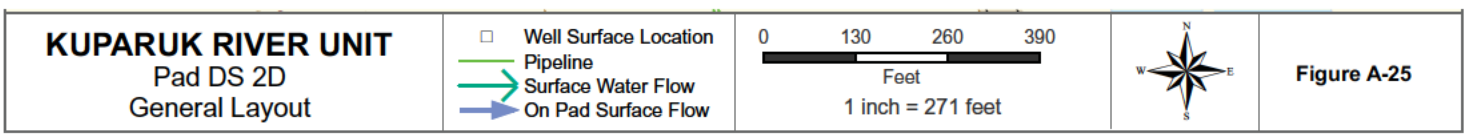

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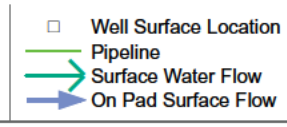
KUPARUK RIVER UNIT
Pad DS 2E
General Layout



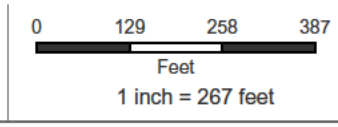


Figure A-26

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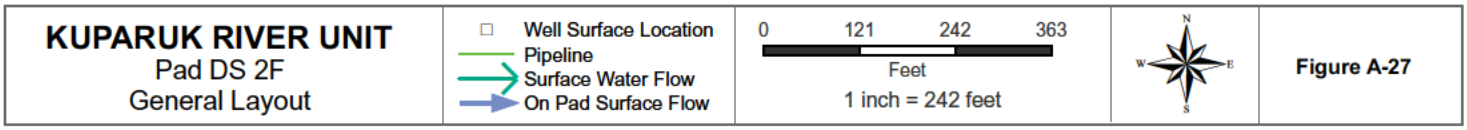

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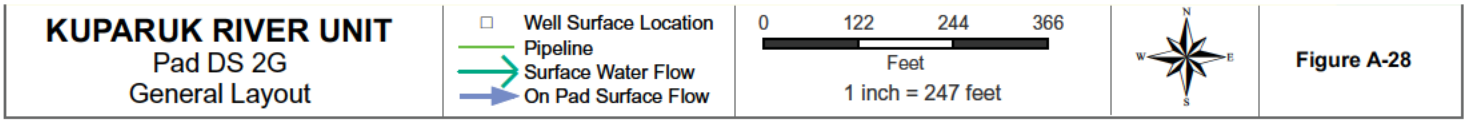

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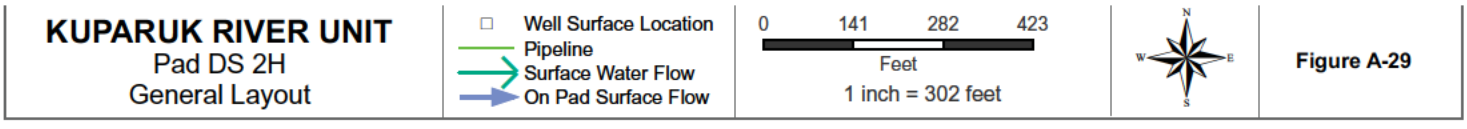

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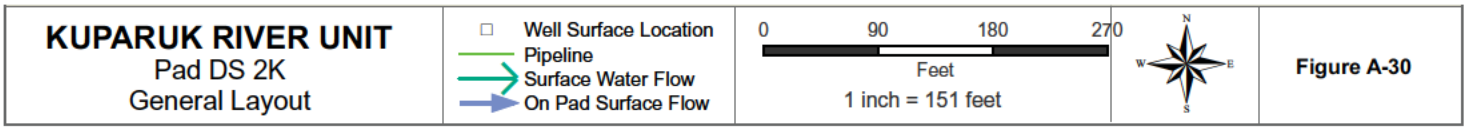

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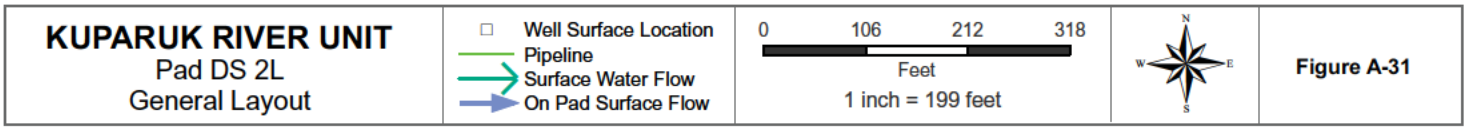

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KUPARUK RIVER UNIT
Pad DS 2M
General Layout

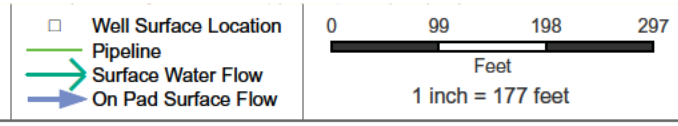
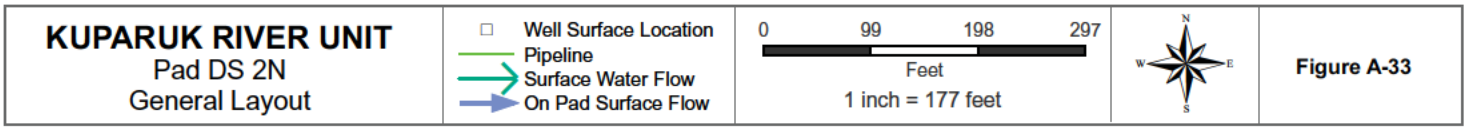


Figure A-32

March 2013, Rev. 0



March 2013, Rev. 0

KUPARUK RIVER UNIT
Pad DS 2T
General Layout

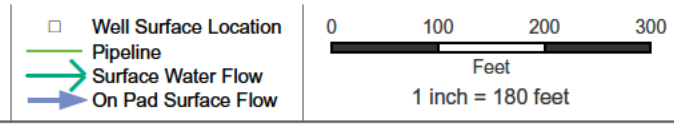
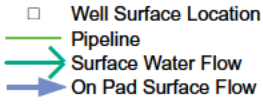


Figure A-34

March 2013, Rev. 0

KUPARUK RIVER UNIT
Pad DS 2U
General Layout



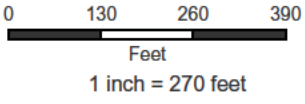
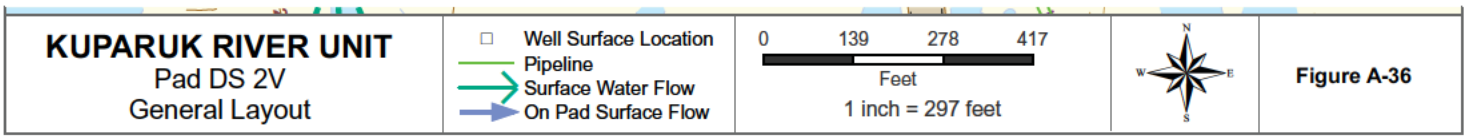
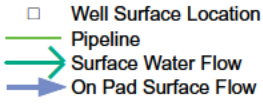


Figure A-35


KUPARUK RIVER UNIT
Pad DS 2V
General Layout
Well Surface Location
Pipeline
Surface Water Flow
On Pad Surface Flow
0
139
278
417
Feet
1 inch = 297 feet
N
W
E
S
Figure A-36

KUPARUK RIVER UNIT
Pad DS 2W
General Layout



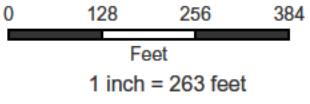
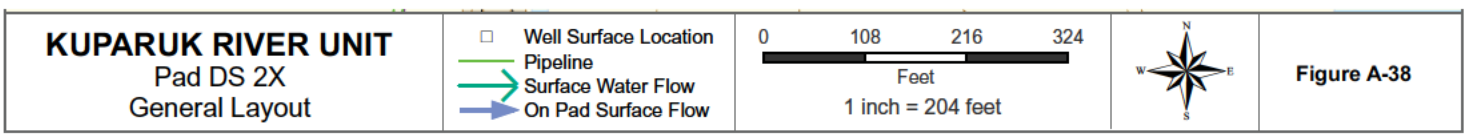
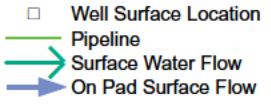


Figure A-37


KUPARUK RIVER UNIT
Pad DS 2X
General Layout
Well Surface Location
Pipeline
Surface Water Flow
On Pad Surface Flow
0
108
216
324
Feet
1 inch = 204 feet
N
W
E
S
Figure A-38

KUPARUK RIVER UNIT
Pad DS 2Z
General Layout



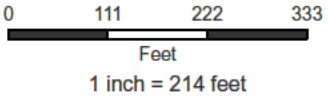
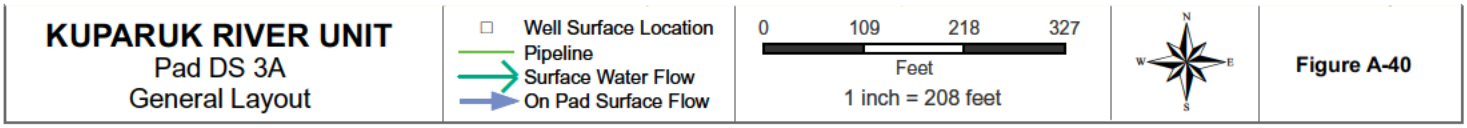
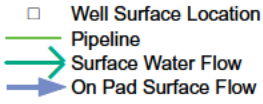


Figure A-39


KUPARUK RIVER UNIT
Pad DS 3A
General Layout
Well Surface Location
Pipeline
Surface Water Flow
On Pad Surface Flow
0
109
218
327
Feet
1 inch = 208 feet
N
W
E
S
Figure A-40

KUPARUK RIVER UNIT
Pad DS 3B
General Layout



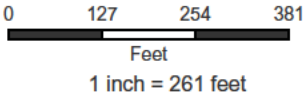
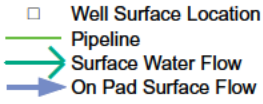


Figure A-41

KUPARUK RIVER UNIT
Pad DS 3C
General Layout



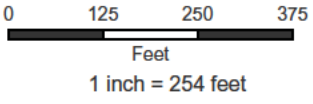
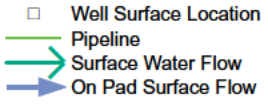


Figure A-42

KUPARUK RIVER UNIT
Pad DS 3F
General Layout



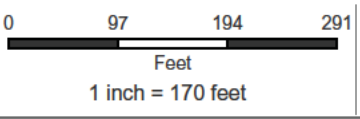
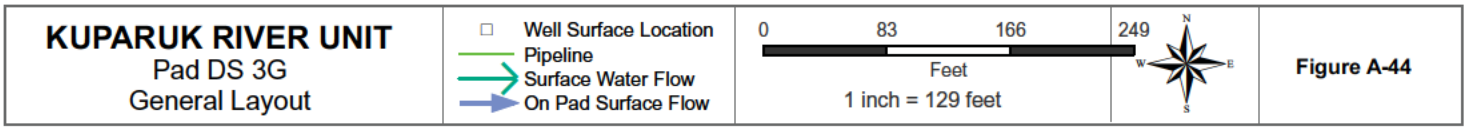
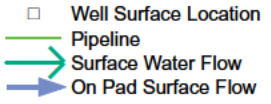


Figure A-43


KUPARUK RIVER UNIT
Pad DS 3G
General Layout
Well Surface Location
Pipeline
Surface Water Flow
On Pad Surface Flow
0
83
166
249
Feet
1 inch = 129 feet
N
W
E
S
Figure A-44

KUPARUK RIVER UNIT
Pad DS 3H
General Layout



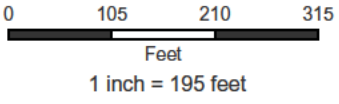
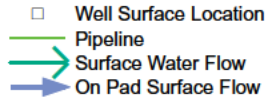


Figure A-45

KUPARUK RIVER UNIT
Pad DS 3I
General Layout



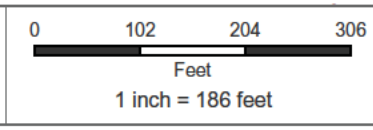
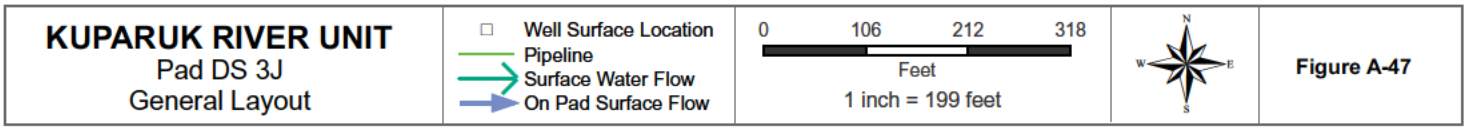
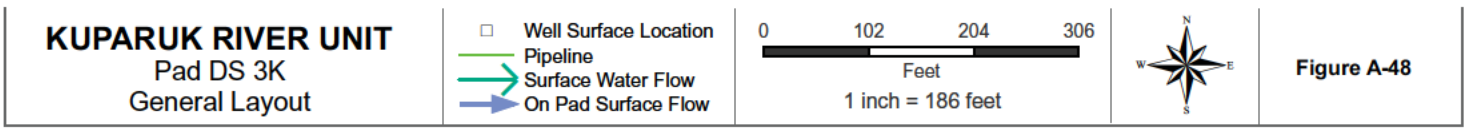
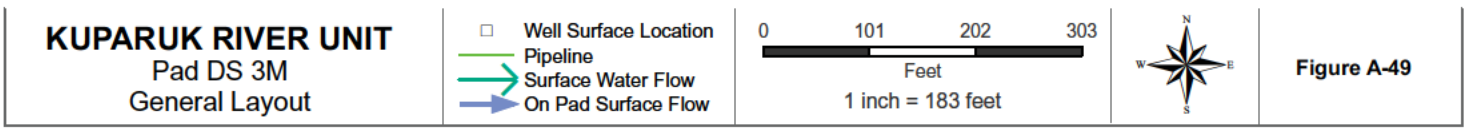
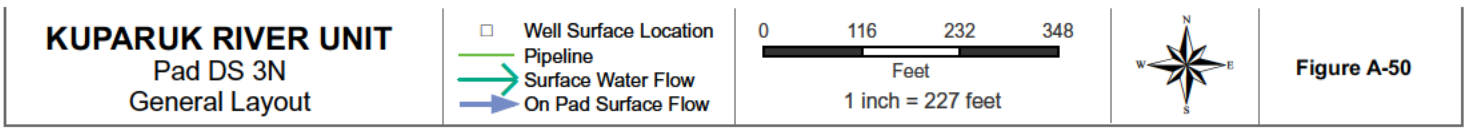


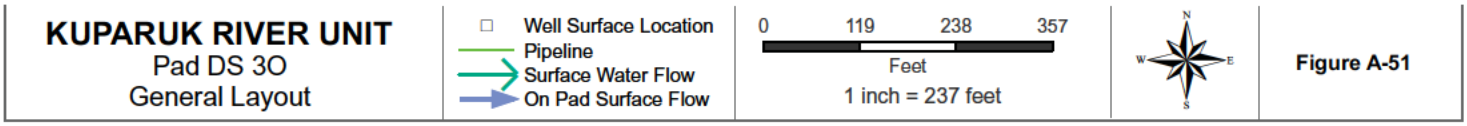
Figure A-46


KUPARUK RIVER UNIT
Pad DS 3J
General Layout
Well Surface Location
Pipeline
Surface Water Flow
On Pad Surface Flow
0
106
212
318
Feet
1 inch = 199 feet
N
W
E
S
Figure A-47

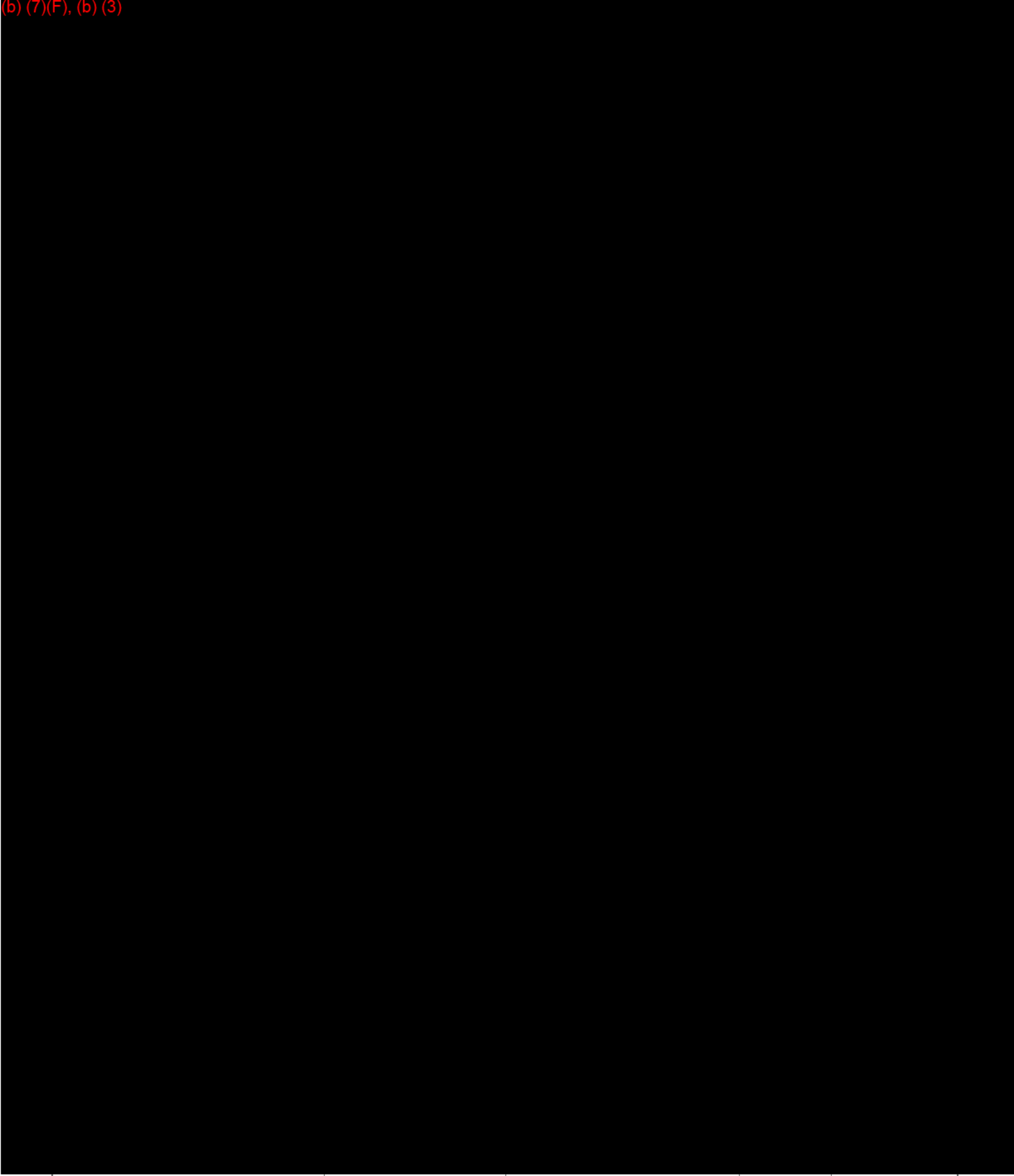

KUPARUK RIVER UNIT
Pad DS 3K
General Layout
Well Surface Location
Pipeline
Surface Water Flow
On Pad Surface Flow
0
102
204
306
Feet
1 inch = 186 feet
N
W
E
S
Figure A-48


KUPARUK RIVER UNIT
Pad DS 3M
General Layout
Well Surface Location
Pipeline
Surface Water Flow
On Pad Surface Flow
0
101
202
303
Feet
1 inch = 183 feet
N
W
E
S
Figure A-49


KUPARUK RIVER UNIT
Pad DS 3N
General Layout
Well Surface Location
Pipeline
Surface Water Flow
On Pad Surface Flow
0
116
232
348
Feet
1 inch = 227 feet
N
W
E
S
Figure A-50


KUPARUK RIVER UNIT
Pad DS 3O
General Layout
Well Surface Location
Pipeline
Surface Water Flow
On Pad Surface Flow
0
119
238
357
Feet
1 inch = 237 feet
N
W
E
S
Figure A-51

(b) (7)(F), (b) (3)



KUPARUK RIVER UNIT
Pad DS 3R
General Layout

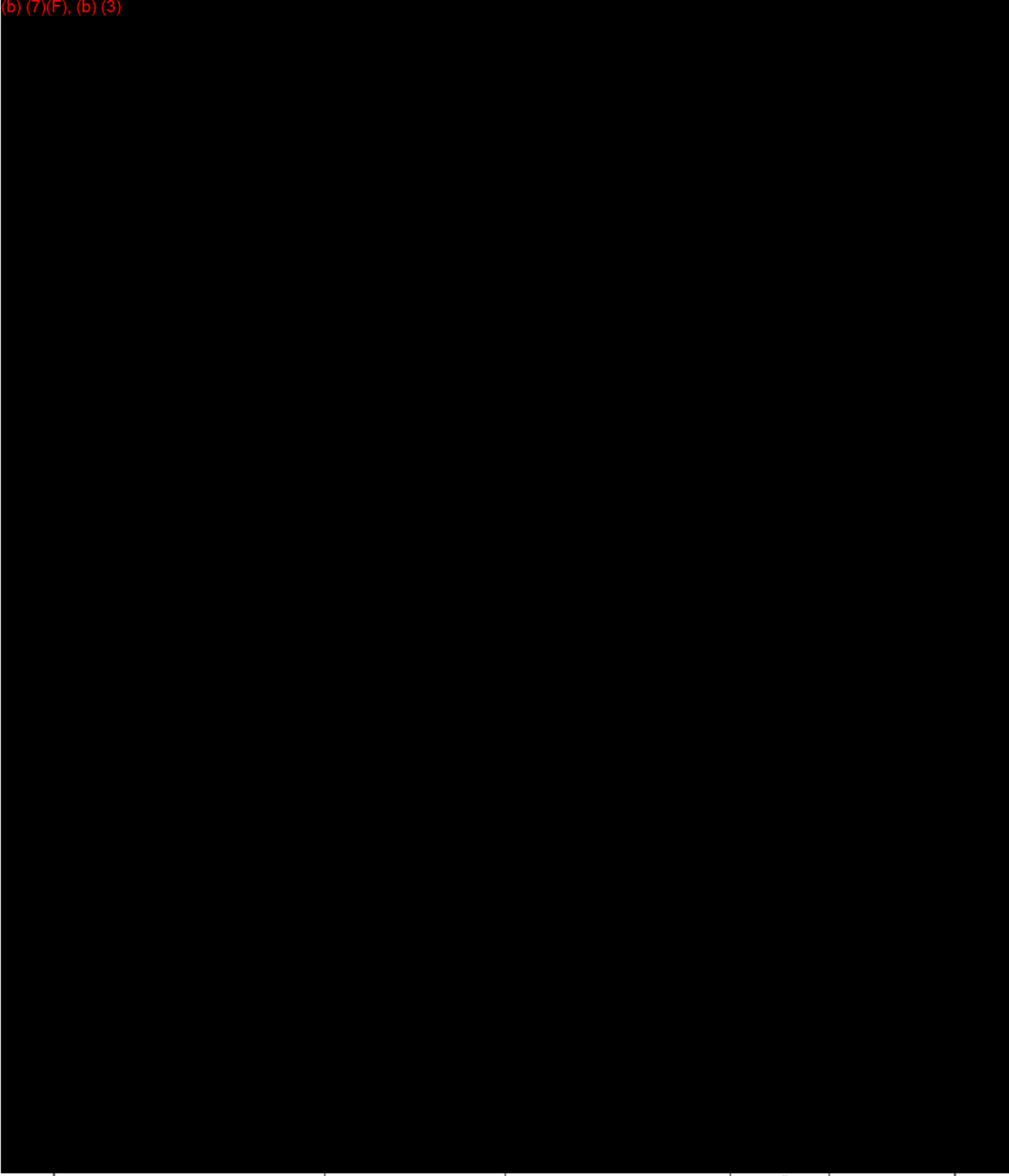
Well Surface Location
Pipeline
Surface Water Flow
On Pad Surface Flow

0 129 258 387
Feet
1 inch = 266 feet

N
W E
S

Figure A-52

(b) (7)(F), (b) (3)



KUPARUK RIVER UNIT
Pad DS 3R
General Layout

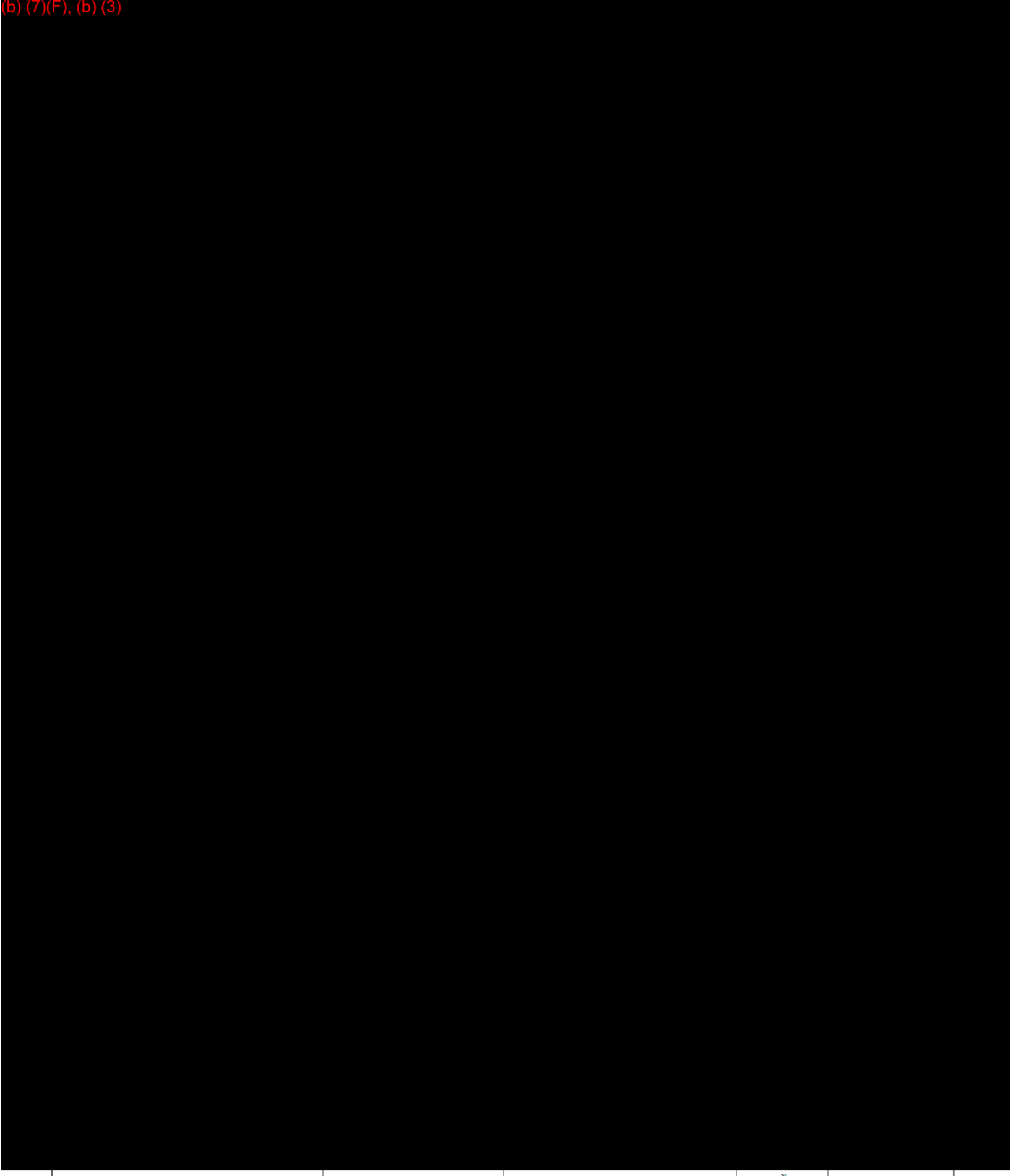
Pipeline
Surface Water Flow

0 0.375 0.75 1.5
Miles
1 inch equals 5,280 feet

N
W E
S

FIGURE A-53

(b) (7)(F), (b) (3)



KUPARUK RIVER UNIT
Pad DS 1M
General Layout

Well Surface Location
Pipeline
Surface Water Flow
On Pad Surface Flow

0 92 184 276
Feet
1 inch = 156 feet

N
W E
S

Figure A-54

KUPARUK RIVER UNIT
Pad DS 2P
General Layout

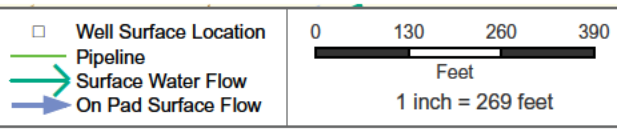
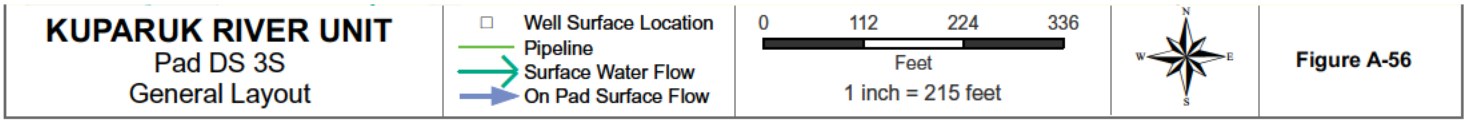
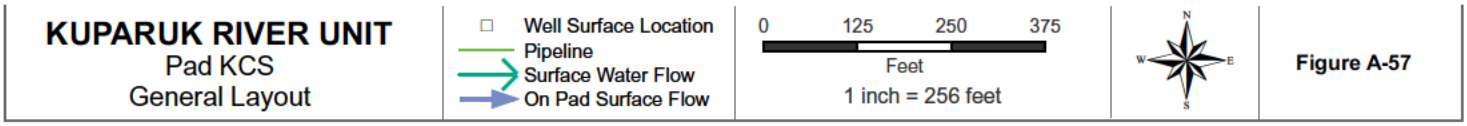
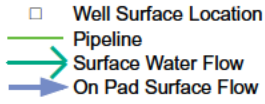


Figure A-55


KUPARUK RIVER UNIT
Pad DS 3S
General Layout
Well Surface Location
Pipeline
Surface Water Flow
On Pad Surface Flow
0
112
224
336
Feet
1 inch = 215 feet
N
W
E
S
Figure A-56


KUPARUK RIVER UNIT
Pad KCS
General Layout
Well Surface Location
Pipeline
Surface Water Flow
On Pad Surface Flow
0
125
250
375
Feet
1 inch = 256 feet
N
W
E
S
Figure A-57

KUPARUK RIVER UNIT
Pad KIC
General Layout



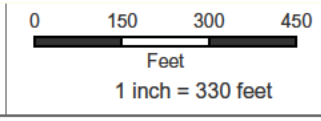
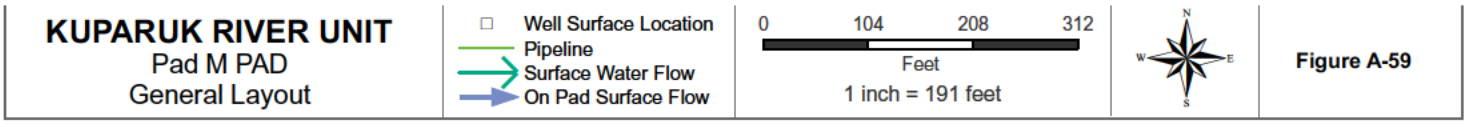
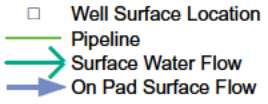


Figure A-58


KUPARUK RIVER UNIT
Pad M PAD
General Layout
Well Surface Location
Pipeline
Surface Water Flow
On Pad Surface Flow
0
104
208
312
Feet
1 inch = 191 feet
N
W
E
S
Figure A-59

KUPARUK RIVER UNIT
Pad STP
General Layout



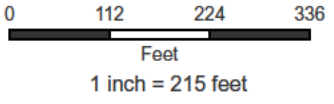
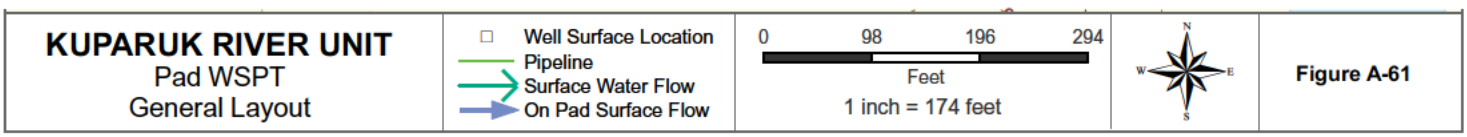
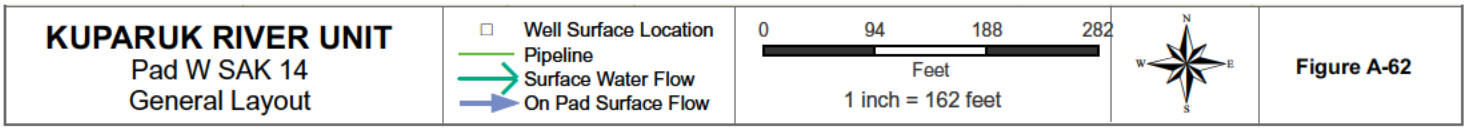
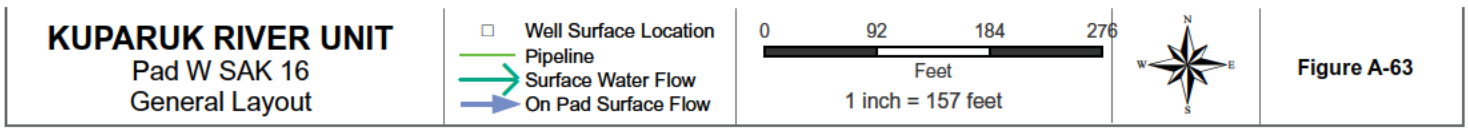


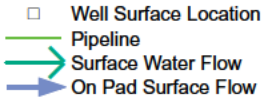
Figure A-60


KUPARUK RIVER UNIT
Pad WSPT
General Layout
Well Surface Location
Pipeline
Surface Water Flow
On Pad Surface Flow
0
98
196
294
Feet
1 inch = 174 feet
N
W
E
S
Figure A-61


KUPARUK RIVER UNIT
Pad W SAK 14
General Layout
Well Surface Location
Pipeline
Surface Water Flow
On Pad Surface Flow
0
94
188
282
Feet
1 inch = 162 feet
N
W
E
S
Figure A-62


KUPARUK RIVER UNIT
Pad W SAK 16
General Layout
Well Surface Location
Pipeline
Surface Water Flow
On Pad Surface Flow
0
92
184
276
Feet
1 inch = 157 feet
N
W
E
S
Figure A-63

KUPARUK RIVER UNIT
Pad W SAK 24A
General Layout



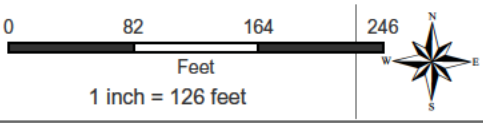
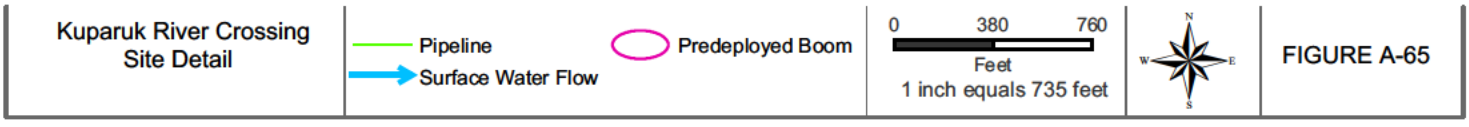
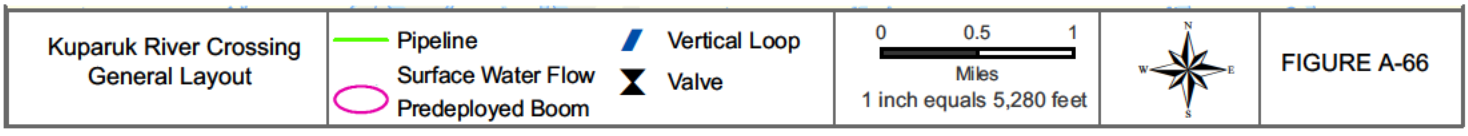
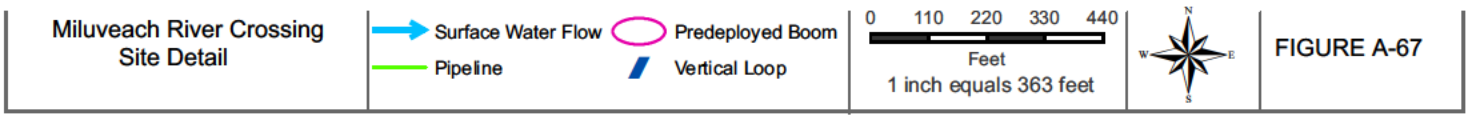
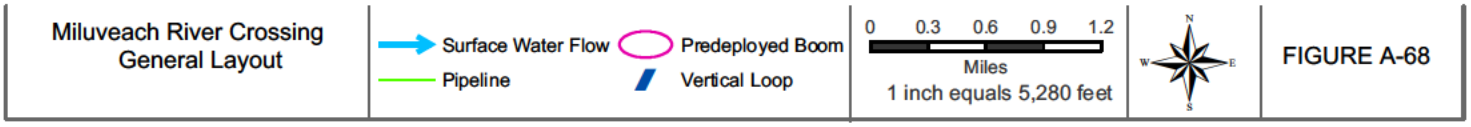


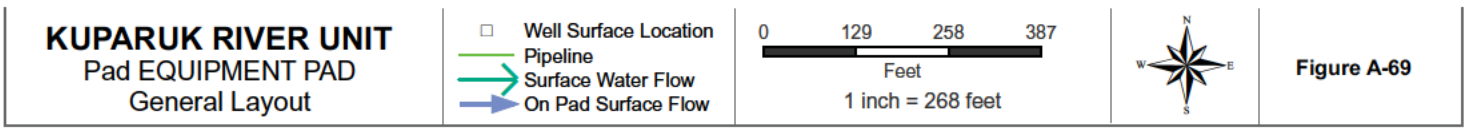
Figure A-64


Kuparuk River Crossing
Site Detail
Pipeline
Surface Water Flow
Predeployed Boom
0
380
760
Feet
1 inch equals 735 feet
N
W
E
S
FIGURE A-65


Kuparuk River Crossing
General Layout
Pipeline
Surface Water Flow
Predeployed Boom
Vertical Loop
Valve
0
0.5
1
Miles
1 inch equals 5,280 feet
N
W
E
S
FIGURE A-66


Miluveach River Crossing
Site Detail
Surface Water Flow
Pipeline
Predeployed Boom
Vertical Loop
0 110 220 330 440
Feet
1 inch equals 363 feet
N
W
E
S
FIGURE A-67


Miluveach River Crossing
General Layout
Surface Water Flow
Pipeline
Predeployed Boom
Vertical Loop
0 0.3 0.6 0.9 1.2
Miles
1 inch equals 5,280 feet
N
W
E
S
FIGURE A-68


KUPARUK RIVER UNIT
Pad EQUIPMENT PAD
General Layout
Well Surface Location
Pipeline
Surface Water Flow
On Pad Surface Flow
0
129
258
387
Feet
1 inch = 268 feet
N
W
E
S
Figure A-69

ConocoPhillips Alaska, Inc.			KUPARUK AND OLIKTOK PIPELINES OPERATIONS RIGHT-OF-WAY Figure A 70a	
Date: 10/25/2013	**Sheet:** 1 of 2	**MXD Name:** KPL_OPL_ROW_Fig1_2013.mxd	**Drawn:** TMN	**Rev:** 3

ConocoPhillips Alaska, Inc.

Figure A 70b

KUPARUK AND OLIKTOK PIPELINES OPERATIONS RIGHT-OF-WAY

Date:	Sheet:	MXD Name:	Drawn:	Rev:
10/25/2013	2 of 2	KPL_OPL_ROW_Fig2_2013.mxd	TMN	3

APPENDIX B:

ADEC REGULATED OIL STORAGE TANKS

TABLE B-1
KUPARUK ADEC REGULATED OIL STORAGE TANKS

FACILITY	MODULE	ID	SERVICE	NOMINAL DESIGN CAPACITY (BBL)	CONSTRUCT. DATE	CONSTRUCT. STANDARD	FOUNDATION	SECONDARY CONTAINMENT	CONTAINMENT VOLUME (BBL)	CONTAINMENT LINER MATERIAL	LEAK DETECTION / CORROSION PROTECTION	ELEVATED / ON GRADE	OVERFILL PROTECTION	LAST; NEXT EXTERNAL INSPECTION	LAST; NEXT INTERNAL INSPECTION	WAIVERS IN EFFECT	COMMENTS
Airport	723	V-702	Jet fuel storage		1980	API 650	Platform on pilings in gravel	Steel wall/liner		COOLEY L1023	DM	E	SG	2010; 2014	2006; 2016	4/8/2014	SGS
CPF1	75	T1-P101A	Crude		1985	API 650	Gravel	Gravel dike/liner		ORTLA	DM Cathodic	O	CLI	2011; 2016	2011; 2021		
CPF1	75	T1-P101B	Crude		1986	API 650	Gravel	Gravel dike/liner		ORTLA	DM Cathodic	O	CLI	2010; 2015	2005; 2015		SGS
CPF1	140	T1-101	Slop oil tank		1981	API 650	Platform on pilings in gravel	Steel wall/liner		SEAMAN ORTLA 8228	DM	E	CLI/SG	2011; 2016	2011; 2021		SGS
CPF1	170	T-175	Emulsion breaker		1983	API 650	Platform on pilings in gravel	Steel wall/liner		L10235DEP	DM	E	CLI/MS	2010; 2015	2005; 2015		SGS
CPF1	170	T-177	Ideal plus lube oil		1980	API 650	Platform on pilings in gravel	Steel wall/liner		L10235DEP	DM	E	CLI/MS	2013; 2018	2008; 2018		SGS
CPF1	207	T-201	Diesel storage		1979	API 650	Platform on pilings in gravel	Steel wall/liner		HDPE	DM	E	CLI/MS	2013; 2018	2008; 2018		SGS
CPF1	1002	T-1002A	Oily waste storage		1980		Platform on pilings in gravel	Steel wall/liner		HDPE	DM Cathodic	E	CLI/SG	2010; 2015	2005; 2015		SGS
CPF1	1002	T-1002B	Oily waste storage		1980		Platform on pilings in gravel	Steel wall/liner		HDPE	DM	E	CLI/SG	2010; 2015	2005; 2015		SGS
CPF1	2202	T-2201	Produced water		1981	API 650	Platform on pilings in gravel	Steel wall/liner		HDPE	DM Cathodic	E	CLI/SG	2013; 2014	2003; 2014	Containment size (2/13/04 ADEC waiver)	SGS Comprehensive External inspection in lieu of Internal in 2013
CPF1	2202	T-2202	Produced water		1981	API 650	Platform on pilings in gravel	Steel wall/liner		HDPE	DM Cathodic	E	CLI/SG	2010; 2015	2005; 2015	Containment size (2/13/04 ADEC waiver)	SGS
CPF1	TK BAT	19-501	Diesel storage		1979	API 650	Platform on pilings in gravel	Steel wall/liner		HDPE	DM	E	CLI/MS	2010; 2015	2005; 2015		SGS
CPF1	TK BAT	19-502	Diesel storage		1979	API 650	Platform on pilings in gravel	Steel wall/liner		HDPE	DM	E	CLI/MS	2013; 2018	2008; 2018		SGS
CPF1	TK BAT	19-503	Diesel storage		1979	API 650	Platform on pilings in gravel	Steel wall/liner		HDPE	DM	E	CLI/MS	2013; 2018	2008; 2018		SGS
CPF1	TK BAT	19-504	Diesel storage		1984	API 650	Platform on pilings in gravel	Steel wall/liner		HDPE	DM	E	CLI/MS	2013; 2018	2008; 2018		SGS
CPF1		T-1005	Contaminated fresh water		1982	API 650	Platform on pilings in gravel	Steel wall/liner		HDPE	DM Cathodic	E	CLI	2013; 2015	2005; 2015		SGS
CPF1		T-1009	Oily waste (recycle)		1990	API 650	Platform on pilings in gravel	Steel wall/liner		HDPE & COOLEY	DM Cathodic	E	CLI	2009; 2014	2004; 2014		SGS
CPF2	101	T-AN105	Sandjet settling tank		1984	API 650	Platform on pilings in gravel	Steel module		Sheet Metal	DM	E	CLI	2009; 2014	2004; 2014	Containment size (2/19/09 ADEC waiver)	SGS
CPF2	4206	T-4201	Diesel storage		1984	API 650	Platform on pilings in gravel	Gravel dike/liner		COOLEY L1023	DM	E	CLI	2011; 2016	2006; 2016		SGS
CPF2	CM02	T-CM01	Seawater or produced water		1984	API 650	Platform on pilings in gravel	Steel wall/liner		SEAMAN 8228	DM Cathodic	E	CLI	2011; 2016	2011; 2021	Containment size (2/13/04 ADEC waiver)	SGS
CPF2	CM02	T-CM02	Produced water		1984	API 650	Platform on pilings in gravel	Steel wall/liner		SEAMAN 8228	DM Cathodic	E	CLI	2011; 2016	2011; 2021	Containment size (2/13/04 ADEC waiver)	SGS
CPF2	YARD	T-AN177	Ideal plus lube oil		1984	API 650	Platform on pilings in gravel	Steel wall/liner		COOLEY L1023	DM	E	MS	2010; 2015	2005; 2015		SGS
CPF2		T1-101	Slop oil tank		1983	API 650	Platform on pilings in gravel	Steel wall/liner		ORTLA 8228	DM Cathodic	E	CLI/SG	2010; 2015	2005; 2015	Containment size (2/13/04 ADEC waiver)	SGS
CPF2		T1-P201A****	Dry crude		1986	API 650	Gravel	Gravel dike/liner		ORTLA 8228	DM Cathodic	O	CLI	2013; 2018	2008; 2018		SGS

TABLE B-1
KUPARUK ADEC REGULATED OIL STORAGE TANKS

FACILITY	MODULE	ID	SERVICE	NOMINAL DESIGN CAPACITY (BBL)	CONSTRUCT. DATE	CONSTRUCT. STANDARD	FOUNDATION	SECONDARY CONTAINMENT	CONTAINMENT VOLUME (BBL)	CONTAINMENT LINER MATERIAL	LEAK DETECTION / CORROSION PROTECTION	ELEVATED / ON GRADE	OVERFILL PROTECTION	LAST; NEXT EXTERNAL INSPECTION	LAST; NEXT INTERNAL INSPECTION	WAIVERS IN EFFECT	COMMENTS
CPF2		T1-P201B	Dry crude (divert)		1986	API 650	Gravel	Gravel dike/liner		ORTLA 8228	DM Cathodic	O	CLI	2009; 2014	2004; 2014		SGS
CPF3	P302	T-EF06	Produced / waste water		1985	API 650	Module floor	Module			DM	E	CLI	2013; 2016	2006; 2016		
CPF3	P325	T-EF01	Slop oil tank		1984	API 650	Platform on pilings in gravel	Gravel dike/liner		ORTLA 8228	DM Cathodic	E	CLI	2013; 2018	2008; 2018		SGS
CPF3	P325	T-EF62	Lube/seal oil		1985	API 650	Platform on pilings in gravel	Gravel dike/liner		ORTLA 8228	DM	E	CLI/MS	2013; 2018	2008; 2018		SGS
CPF3	P327	T-EF03	Diesel storage		1984	API 650	Platform on pilings in gravel	Gravel dike/liner		COOLEY L1023	DM Cathodic	E	CLI	2013; 2018	2008; 2018		SGS
CPF3	PEF52	T-EF52	Produced water		1986	API 650	Platform on pilings in gravel	Steel wall/liner		ORTLA 8228	DM Cathodic	E	CLI	2013; 2018	2013; 2023	Containment size (2/13/04 ADEC waiver)	SGS
DS2B		T-2B01	Diesel tank		1985	API 650	Platform on pilings in gravel	Gravel dike/liner		HDPE	DM	E	CLI/MS	2009; 2014	2009; 2019		SGS
DS2C		T-2C01	Diesel tank		1985	API 650	Platform on pilings in gravel	Gravel dike/liner		HDPE	DM	E	CLI/MS	2013; 2018	2009; 2019		SGS
DS2D		T-2D01	Diesel tank		1985	API 650	Platform on pilings in gravel	Gravel dike/liner		HDPE	DM	E	CLI/MS	2013; 2018	2008; 2018		SGS
DS2F		T-2F01	Diesel tank		1985	API 650	Platform on pilings in gravel	Gravel dike/liner		COOLEY L1023	DM	E	CLI/MS	2009; 2014	2009; 2019		SGS
DS2G		T-2G01	Diesel tank		1985	API 650	Platform on pilings in gravel	Gravel dike/liner		HDPE	DM	E	CLI/MS	2010; 2015	2010; 2020		SGS
DS2H		T-2H01	Diesel tank		1985	API 650	Platform on pilings in gravel	Gravel dike/liner		HDPE	DM	E	CLI/MS	2009; 2014	2009; 2019		SGS
DS2N		T-2N01	Diesel tank		2001	UL 142	VSM supported module floor	Steel wall/liner		COOLEY L1023	DM	E	CLI/MS	2011; 2016	2011; 2021	Construction standard (10/2/02 ADEC waiver)	No coating on interior; painted exterior
DS2T		T-3M01	Diesel tank		1986	API 650	Platform on pilings in gravel	Steel wall/liner		HDPE	DM	E	CLI/MS	2013; 2018	2008; 2018		SGS
DS2U		T-2U01	Diesel tank		1985	API 650	Platform on pilings in gravel	Gravel dike/liner		COOLEY L1023	DM	E	CLI/MS	2009; 2014	2009; 2019		SGS
DS2W		T-2W01	Diesel tank		1985	API 650	Platform on pilings in gravel	Gravel dike/liner		HDPE	DM	E	CLI/MS	2011; 2016	2011; 2021		SGS
DS2X		T-2X01	Diesel tank		1985	API 650	Platform on pilings in gravel	Gravel dike/liner		HDPE	DM	E	CLI/MS	2013; 2018	2008; 2018		SGS
DS2Z		T-2Z01	Diesel tank		1985	API 650	Platform on pilings in gravel	Gravel dike/liner		HDPE	DM	E	CLI/MS	2013; 2018	2008; 2018		SGS

* Leak Detection and Overfill Protection Acronyms:
DM = Daily Monitoring
CLI = Constant Level Indicator
MS = Manual Strapping
SG = Sight Glass
SGS = Sensitive Gauging System
Note: See Table 4-5 for a listing of Constant Level Indicators used on regulated storage tanks. Tanks listed are owned and operated by CPAI.

** CPF1 and CPF2 Divert Tank A & B Nominal Design Capacity is actually slightly less than 55,000 bbl due to tank bottom repairs hat raised the floor and decreased the storage capacity by approximately 700 bbls. Actual Nominal

*** Tank T-EF06 is located inside a module with a sealed floor and sumps that can pump fluids to tank T-EF01. The sumps also have overflow lines that drain into a lined pit. The secondary containment volume is based on he

**** This is a DOT Breakout Tank.

TABLE B-2
CPAI-OWNED PORTABLE ADEC REGULATED OIL STORAGE TANKS AVAILABLE FOR USE

TAG NUMBER	TANK DESCRIPTION	VOLUME (BBL)	VOLUME (GAL)	CONTENTS	FABRICATION DATE	CONSTRUCTION STANDARD	LAST NEXT EXTERNAL INSPECTION	LAST NEXT INTERNAL INSPECTION	SERVICE HISTORY	COMMENTS
AK-2408	Vertical			Diesel	1980	Closed top/skid	2012; 2017	2012; 2017		
AK-2424	Vertical			Diesel	1980	Closed top/skid	2011; 2016	2011; 2021		
AP-T-61043	White hydrocarbon tank (Hector Tank)			Aviation Jet A fuel	1998	ADEC Waiver	2013; 2014	2003; 2023		Former Tag CF-T-76004 Double-wall, placed in containment ADEC Waiver on file, Section 2.6 Inspected per STI-SP001
AP-T-76101	Upright			Varies	2005	API 650	2010; 2015	New 2005; 2015		
AP-T-76135	Tiger Tank			Varies	2005	ADEC Waiver	2011; 2016	2011; 2021		ADEC Waiver on file, Section 2.6
AP-T-76197	Open Top			Varies	2006	ADEC Waiver	2013; 2018	2013; 2023		ADEC Waiver on file, Section 2.6 first year of service was 2008
AP-T-76198	Open Top			Varies	2006	ADEC Waiver	2011; 2016	New 2006; 2016		ADEC Waiver on file, Section 2.6
AP-T-76223	Upright			Varies	2007	API 650 App J	2012; 2017	2012; 2022		
AP-T-76224	Upright			Varies	2007	API 650 App J	2012; 2017	2012; 2022		
AP-T-76225	Upright			Varies	2007	API 650 App J	2012; 2017	2012; 2022		
AP-T-76350	Upright			Varies	2009	API 650	New 2009; 2014	New 2009; 2019	New 2009	
AP-T-76351	Upright			Varies	2009	API 650	New 2009; 2014	New 2009; 2019	New 2009	
AP-T-76352	Tiger Tank			Varies	2009	ADEC Waiver	New 2009; 2014	New 2009; 2019	New 2009	ADEC Waiver on file, Section 2.6

TABLE B-2
CPAI-OWNED PORTABLE ADEC REGULATED OIL STORAGE TANKS AVAILABLE FOR USE

TAG NUMBER	TANK DESCRIPTION	VOLUME (BBL)	VOLUME (GAL)	CONTENTS	FABRICATION DATE	CONSTRUCTION STANDARD	LAST NEXT EXTERNAL INSPECTION	LAST NEXT INTERNAL INSPECTION	SERVICE HISTORY	COMMENTS
AP-T-76362	Double-wall upright			Varies	2008	API 12F	New 2009; 2014	New 2009; 2019	New 2009; Atigun 325	
AP-T-76363	Double-wall upright			Varies	2008	API 12F	New 2009; 2014	New 2009; 2019	New 2009; Atigun 326	
AP-T-76364	Double-wall upright			Varies	2008	API 12F	New 2009; 2014	New 2009; 2019	New 2009; Atigun 327	
AP-T-76393	Double-wall upright			Varies	2009	API 12F	New 2009; 2014	New 2009; 2019		
AP-T-76394	Double-wall upright			Varies	2009	API 12F	New 2009; 2014	New 2009; 2019		
AP-T-76395	Double-wall upright			Varies	2009	API 12F	New 2009; 2014	New 2009; 2019		
AP-T-76396	Double-wall upright			Varies	2009	API 12F	New 2009; 2014	New 2009; 2019		
AP-T-76397	Double-wall upright			Varies	2009	API 12F	New 2009; 2014	New 2009; 2019		
CF-T-76004	Horizontal open top			Misc. hydrocarbon service	ND	ADEC Waiver	2012; 2016	2012; 2020		ADEC Waiver on file, Section 2.6
CF-T-76005	Horizontal open top			Misc. hydrocarbon service	ND	ADEC Waiver	2012; 2017	2007; 2017		ADEC Waiver on file, Section 2.6
CF-T-76006	Black Tiger Tank			Well bore fluids	2000	ADEC Waiver	2009; 2014	2009; 2019		ADEC Waiver on file, Section 2.6
CF-T-76007	Black Tiger Tank			Well bore fluids	2000	ADEC Waiver	2013; 2018	2013; 2023		ADEC Waiver on file, Section 2.6
CF-T-76017	Gray Upright			Multi-use, potential hydrocarbons	1998	API 12 F (11th Edition)	2012; 2017	2007; 2017		
CF-T-76033	Gray Upright			Misc. hydrocarbon service	2003	API 650	2012; 2017	2012; 2022		

TABLE B-2
CPAI-OWNED PORTABLE ADEC REGULATED OIL STORAGE TANKS AVAILABLE FOR USE

TAG NUMBER	TANK DESCRIPTION	VOLUME (BBL)	VOLUME (GAL)	CONTENTS	FABRICATION DATE	CONSTRUCTION STANDARD	LAST NEXT EXTERNAL INSPECTION	LAST NEXT INTERNAL INSPECTION	SERVICE HISTORY	COMMENTS
CF-T-76070	Brown Open Top			Misc. hydrocarbon service	2003	API 650	2009; 2014	2009; 2018		
CF-T-76071	Brown Tiger Tank			Misc. hydrocarbon service	2003	API 650	2013; 2018	2013; 2023		
CF-T-76210	Upright			Brine, potential hydrocarbons	2004	API 650 App J	2009; 2014	2009; 2019		
CF-T-76819	Upright			Misc. hydrocarbon service	2002	API 650 (10th Edition)	2012; 2017	2007; 2014		
CF-T-76820	Upright			Misc. hydrocarbon service	2002	API 650 (10th Edition)	2012; 2014	2007; 2014		
DEG-8691	Vertical			Diesel	1984	Closed top/skid	2010; 2015	2010; 2015		
DEG-8692	Vertical			Diesel	1984	Closed top/skid	2013; 2018	2013; 2018		
DEG-8693	Vertical			Varies	1983	Closed top/skid	2010; 2015	2010; 2015		
KP-4132	Horizontal			Varies	ND	Open top/skid	2009; 2014	2009; 2019		
KSP-0511	Tiger Tank			Varies	1992	Closed top/wheels	2009; 2014	2009; 2019		
KSP-0512	Tiger Tank			Varies	1992	Closed top/wheels	2010; 2015	2010; 2015		
PGE-86AD	Vertical cylinder			Varies	1981	Closed top/skid	2013; 2018	2013; 2018		
PGE-86AH	Vertical			Varies	1984	Closed top/skid	2009; 2014	2009; 2014		
PGE-86AI	Vertical			Varies	1984	Closed top/skid	2013; 2018	2013; 2023		
PGE-86AN	Vertical			Varies	1984	Closed top/skid	2013; 2018	2013; 2023		

TABLE B-2
CPAI-OWNED PORTABLE ADEC REGULATED OIL STORAGE TANKS AVAILABLE FOR USE

TAG NUMBER	TANK DESCRIPTION	VOLUME (BBL)	VOLUME (GAL)	CONTENTS	FABRICATION DATE	CONSTRUCTION STANDARD	LAST NEXT EXTERNAL INSPECTION	LAST NEXT INTERNAL INSPECTION	SERVICE HISTORY	COMMENTS
PGE-86AP	Vertical			Varies	1984	Closed top/skid	2010; 2015	2010; 2020		
PGE-86AR	Vertical			Varies	1984	Closed top/skid	2013; 2018	2008; 2018		
PGE-86AU	Vertical cylinder			Varies	ND	Closed top/skid	2013; 2018	2013; 2023		
PGE-86AV	Vertical			Varies	1984	Closed top/skid	2013; 2017	2008; 2017		
PGE-86AW	Vertical			Varies	1984	Closed top/skid	2009; 2014	2004; 2014		
PGE-86AY	Vertical			Varies	1984	Closed top/skid	2010; 2015	2010; 2020		
PGE-86AZ	Vertical			Varies	1984	Closed top/skid	2009; 2014	2004; 2014		
PGE-86BC	Horizontal cylinder			Varies	1985	Open top/skid	2011; 2016	2011; 2021		
PGE-86BD	Horizontal cylinder			Varies	1985	Open top/skid	2010; 2015	2010; 2020		
PGE-86BE	Vertical			Varies	1985	Closed top/skid	2009; 2014	2004; 2014		
PGE-86BG	Vertical			Varies	1985	Closed top/skid	2013; 2018	2013; 2023		
PGE-86CE	Vertical cylinder			Varies	1985	Closed top/skid	2013; 2018	2008; 2018		
PGE-86CF	Vertical cylinder			Varies	1985	Closed top/skid	2013; 2018	2008; 2018		
PGE-87	Horizontal cylinder			Varies	1984	Open top/skid	2013; 2018	2013; 2018		
PGE-87AC	Horizontal cylinder			Varies	ND	Open top/skid	2010; 2015	2010; 2020		

TABLE B-2
CPAI-OWNED PORTABLE ADEC REGULATED OIL STORAGE TANKS AVAILABLE FOR USE

TAG NUMBER	TANK DESCRIPTION	VOLUME (BBL)	VOLUME (GAL)	CONTENTS	FABRICATION DATE	CONSTRUCTION STANDARD	LAST NEXT EXTERNAL INSPECTION	LAST NEXT INTERNAL INSPECTION	SERVICE HISTORY	COMMENTS
PGE-87AD	Horizontal			Varies	ND	Open top/skid	2011; 2016	2011; 2016		
SST-001	Vertical			Varies	2000	API 650	2011; 2016	2011; 2021		
SST-002	Vertical			Varies	2000	API 650	2011; 2016	2011; 2021		
SST-003	Vertical			Varies	2001	API 650	2011; 2016	2011; 2021		
SST-004	Vertical			Varies	2001	API 650	2011; 2016	2011; 2021		
SST-005	Vertical			Varies	2001	API 650	2011; 2016	2011; 2021		
SST-006	Vertical			Varies	2001	API 650	2011; 2016	2011; 2021		
SST-007	Vertical			Varies	2001	API 650	2011; 2016	2011; 2021		
SST-008	Vertical			Varies	2001	API 650	2011; 2016	2011; 2021		
SST-009	Vertical			Varies	2001	API 650	2011; 2016	2011; 2021		
SST-010	Vertical			Varies	2001	API 650	2011; 2016	2011; 2021		
SST-015	Horizontal Steelfab Flowback			Varies	2006	ADEC BBFM-205126-09/05 UL 142	2011; 2016	2011; 2016		Double-wall, tank-within-tank design
SST-016	Horizontal Steelfab Flowback			Varies	2006	ADEC BBFM-205126-09/05 UL 142	2011; 2016	2011; 2016		Double-wall, tank-within-tank design
SST-017	Horizontal Steelfab Flowback			Varies	2006	ADEC BBFM-205126-09/05 UL 142	2011; 2016	2011; 2016		Double-wall, tank-within-tank design
SST-018	Horizontal Steelfab Flowback			Varies	2006	ADEC BBFM-205126-09/05 UL 142	2011; 2016	2011; 2016		Double-wall, tank-within-tank design

TABLE B-2
CPAI-OWNED PORTABLE ADEC REGULATED OIL STORAGE TANKS AVAILABLE FOR USE

TAG NUMBER	TANK DESCRIPTION	VOLUME (BBL)	VOLUME (GAL)	CONTENTS	FABRICATION DATE	CONSTRUCTION STANDARD	LAST NEXT EXTERNAL INSPECTION	LAST NEXT INTERNAL INSPECTION	SERVICE HISTORY	COMMENTS
SST-019	Horizontal Steelfab Flowback			Varies	2006	ADEC BBFM-205126-09/05 UL 142	2011; 2016	2011; 2016		Double-wall, tank-within-tank design
SST-020	Horizontal Steelfab Flowback			Varies	2006	ADEC BBFM-205126-09/05	2011; 2016	2011; 2016		Double-wall, tank-within-tank design
SST-027	Horizontal Steelfab Flowback			Varies	2007	ADEC BBFM-205126-09/05 UL 142	2013; 2018	2013; 2018		Double-wall, tank-within-tank design
SST-028	Horizontal Steelfab Flowback			Varies	2007	ADEC BBFM-205126-09/05 UL 142	2013; 2018	2013; 2018		Double-wall, tank-within-tank design
SST-029	Horizontal Steelfab Flowback			Varies	2007	ADEC BBFM-205126-09/05 UL 142	2012; 2017	2012; 2022		Double-wall, tank-within-tank design
SST-065	Horizontal Steelfab Flowback			Varies	2009	ADEC BBFM-205126-09/05 UL 142	New 2009; 2014	New 2009; 2019	New 2009	Double-wall, tank-within-tank design
SST-066	Horizontal Steelfab Flowback			Varies	2009	ADEC BBFM-205126-09/05 UL 142	New 2009; 2014	New 2009; 2019	New 2009	Double-wall, tank-within-tank design
SST-067	Horizontal Steelfab Flowback			Varies	2009	ADEC BBFM-205126-09/05	2010; 2015	2010; 2020	New 2009	Double-wall, tank-within-tank design
SST-071	Horizontal Steelfab Flowback			Varies	2010	ADEC BBFM-205126-09/05 UL 142	New 2010; 2015	New 2010; 2020	New 2010	Double-wall, tank-within-tank design
SUR001	Double-wall upright			Varies	2007	API 12F	2012; 2017	2007; 2017		Former ID Atigun 250
SUR002	Double-wall upright			Varies	2007	API 12F	2012; 2017	2007; 2017		Former ID Atigun 251
SUR003	Double-wall upright			Varies	2008	API 12F	2013; 2018	2013; 2018		Former ID Atigun 286
SUR004	Double-wall upright			Varies	2008	API 12F	2013; 2018	2013; 2018		Former ID Atigun 287
SUR005	Double-wall upright			Varies	2008	API 12F	2013; 2018	2013; 2018		Former ID Atigun 306
SUR006	Double-wall upright			Varies	2008	API 12F	2013; 2018	2013; 2018		Former ID Atigun 303

TABLE B-2
CPAI-OWNED PORTABLE ADEC REGULATED OIL STORAGE TANKS AVAILABLE FOR USE

TAG NUMBER	TANK DESCRIPTION	VOLUME (BBL)	VOLUME (GAL)	CONTENTS	FABRICATION DATE	CONSTRUCTION STANDARD	LAST NEXT EXTERNAL INSPECTION	LAST NEXT INTERNAL INSPECTION	SERVICE HISTORY	COMMENTS
T-M101 (SST-011)	Vertical			Varies	2005	API 650	2010; 2015	2005; 2015		
T-M102 (SST-012)	Vertical			Varies	2005	API 650	2010; 2015	2005; 2015		
T-M103 (SST-013)	Vertical			Varies	2005	API 650	2010; 2015	2005; 2015		
T-M104 (SST-014)	Vertical			Varies	2005	API 650	2010; 2015	2005; 2015		

Notes

1. All listed tanks are welded construction. Tanks are owned and operated by CPAI. Listed tanks are typically located in Kuparuk, but may be used at other locations, if needed.
2. Skid-mounted tanks rest approximately 1 to 1 5 feet above the ground.
3. ND = No data available.

TABLE B-3
RENTED OR LEASED PORTABLE ADEC REGULATED OIL STORAGE TANKS AVAILABLE FOR USE

OWNER	TAG NUMBER	TANK DESCRIPTION	VOLUME (BBL)	VOLUME (GAL)	CONTENTS	FABRICATION DATE	CONSTRUCTION STANDARD	EXTERNAL INSPECTION SCHEDULE, LAST; NEXT	INTERNAL INSPECTION SCHEDULE, LAST; NEXT	SERVICE HISTORY	COMMENTS
AIC	19-06	Double-wall, welded steel			Oil; drilling fluids	1999	BBFM-98142.1	2005; 2010	2005; 2010	Continuous since 2000	Not in use at CPAI facilities Construc ion standard approved by ADEC 2/10/05
AIC	20-15	Double-wall, welded steel			Oil; drilling fluids	2000	BBFM-98142.1	2005; 2010	2005; 2010	Continuous since 2000	Not in use at CPAI facilities Construc ion standard approved by ADEC 2/10/05
AIC	22-02	Double-wall, welded steel			Oil; drilling fluids	1999	BBFM-98142.1	2005; 2010	2005; 2010	Continuous since 2000	Not in use at CPAI facilities Construc ion standard approved by ADEC 2/10/05
AIC	23-05	Double-wall, welded steel			Oil; drilling fluids	1999	BBFM-98142.1	2005; 2010	2005; 2010	Continuous since 2000	Not in use at CPAI facilities Construc ion standard approved by ADEC 2/10/05
AIC	24-11	Double-wall, welded steel			Oil; drilling fluids	2000	BBFM-98142.1	2005; 2010	2005; 2010	Continuous since 2000	Not in use at CPAI facilities Construc ion standard approved by ADEC 2/10/05
AIC	29-921	Double-wall, welded steel			Oil; fuel, drilling fluids	1999	API 650	2013; 2018	2013; 2023		
AIC	29-923-070	Double-wall, welded steel			Oil; drilling fluids	2000	BBFM-98142.1	2005; 2010	2005; 2010	Continuous since 2000	Not in use at CPAI facilities Construc ion standard approved by ADEC 2/10/05
Atigun	120	Double-wall, welded steel			Oil; drilling fluids	2006	API-12F	New 2006; 2011	New 2006; 2016	New 2006	Not in use as CPAI facilities
Atigun	123	Double-wall, welded steel			Oil; drilling fluids	2006	API-12F	2011; 2016	New 2006; 2016	New 2006	
Atigun	124	Double-wall, welded steel			Oil; drilling fluids	2006	API-12F	2011; 2016	New 2006; 2016	New 2006	
Atigun	125	Double-wall, welded steel			Oil; drilling fluids	2006	API-12F	2011; 2016	New 2006; 2016	New 2006	
Atigun	126	Double-wall, welded steel			Oil; drilling fluids	2006	API-12F	2011; 2016	New 2006; 2016	New 2006	
Atigun	127	Double-wall, welded steel			Oil; drilling fluids	2006	API-12F	2011; 2016	New 2006; 2016	New 2006	
Atigun	128	Double-wall, welded steel			Oil; drilling fluids	2006	API-12F	2011; 2016	New 2006; 2016	New 2006	

TABLE B-3
RENTED OR LEASED PORTABLE ADEC REGULATED OIL STORAGE TANKS AVAILABLE FOR USE

OWNER	TAG NUMBER	TANK DESCRIPTION	VOLUME (BBL)	VOLUME (GAL)	CONTENTS	FABRICATION DATE	CONSTRUCTION STANDARD	EXTERNAL INSPECTION SCHEDULE, LAST; NEXT	INTERNAL INSPECTION SCHEDULE, LAST; NEXT	SERVICE HISTORY	COMMENTS
Atigun	129	Double-wall, welded steel			Oil; drilling fluids	2006	API-12F	2011; 2016	New 2006; 2016	New 2006	
Atigun	130	Double-wall, welded steel			Oil; drilling fluids	2006	API-12F	New 2006; 2011	New 2006; 2016	New 2006	Not in use as CPAI facilities
Atigun	131	Double-wall, welded steel			Oil; drilling fluids	2006	API-12F	New 2006; 2011	New 2006; 2016	New 2006	Not in use as CPAI facilities
Atigun	252	Double-wall upright			Oil; drilling fluids	2007	API-12F	2012; 2017	New 2007; 2017	New 2007	
Atigun	253	Double-wall upright			Oil; drilling fluids	2007	API-12F	New 2007; 2012	New 2007; 2017	New 2007	Not in use as CPAI facilities
Atigun	254	Double-wall upright			Oil; drilling fluids	2007	API-12F	2011; 2016	2011; 2021	New 2007	
Atigun	255	Double-wall upright			Oil; drilling fluids	2007	API-12F	2012; 2017	New 2007; 2017	New 2007	
Atigun	291	Double-wall upright			Varies	2008	API-12F	New 2009; 2014	New 2009; 2019	New 2009	
Atigun	292	Double-wall upright			Varies	2008	API-12F	New 2009; 2014	New 2009; 2019	New 2009	
Atigun	293	Double-wall upright			Varies	2008	API-12F	New 2009; 2014	New 2009; 2019	New 2009	
Atigun	324	Double-wall upright			Varies	2008	API-12F	New 2009; 2014	New 2009; 2019	New 2009	
Atigun	328	Double-wall upright			Varies	2008	API-12F	New 2009; 2014	New 2009; 2019	New 2009	
Atigun	333	Single wall upright			Varies	2008	API-12F	2011; 2016	2011; 2021		
Atigun	334	Single wall upright			Varies	2008	API-12F	2011; 2016	2011; 2021		

TABLE B-3
RENTED OR LEASED PORTABLE ADEC REGULATED OIL STORAGE TANKS AVAILABLE FOR USE

OWNER	TAG NUMBER	TANK DESCRIPTION	VOLUME (BBL)	VOLUME (GAL)	CONTENTS	FABRICATION DATE	CONSTRUCTION STANDARD	EXTERNAL INSPECTION SCHEDULE, LAST; NEXT	INTERNAL INSPECTION SCHEDULE, LAST; NEXT	SERVICE HISTORY	COMMENTS
Atigun	353	Double-wall upright			Varies	2009	API-12F	2011; 2016	2011; 2021	New 2009	
Atigun	354	Double-wall upright			Varies	2009	API-12F	2011; 2016	2011; 2021	New 2009	
Atigun	355	Double-wall upright			Varies	2009	API-12F	2011; 2015	2011; 2021	New 2009	
Atigun	356	Double-wall upright			Varies	2009	API-12F	2011; 2016	2011; 2019	New 2009	
Atigun	1128	Horizontal open-top			Drilling fluids	2002	None	2014; 2015	2014; 2015		three compartment tank
Atigun	1804	Horizontal Rectangular			Varies	1991	None	2010; 2015	2010; 2020		
Atigun	08-014-2	Single wall upright			Varies	2008	API-12F	2011; 2016	2011; 2021		
Atigun	08-362-7	Single wall upright			Varies	2008	API-12F	2011; 2016	2011; 2021		
MagTec	027291-05	Single wall upright			Varies; drilling fluids	2013	API-12F	New 2013; 2018	New 2013; 2023		
MagTec	027291-09	Single wall upright			Varies; drilling fluids	2013	API-12F	New 2013; 2018	New 2013; 2023		
MagTec	027503-02	Single wall upright			Varies; drilling fluids	2013	API-12F	New 2013; 2018	New 2013; 2023		
MagTec	027503-10	Single wall upright			Varies; drilling fluids	2013	API-12F	New 2013; 2018	New 2013; 2023		
Nabors	42-50056	Open top, “pop off” tank			Trace oil; seawater	1981	None	2005; 2010	2005; 2015	Continuous since 1981	Not in use at CPAI facilities
Rain for Rent	239304	Bi-Level Tiger Tank			Oil; drilling fluids	1994	RFR Spec. 99044	2012; 2017	2007; 2017	Continuous since 1994	CPAI Ref# SST-025

TABLE B-3
RENTED OR LEASED PORTABLE ADEC REGULATED OIL STORAGE TANKS AVAILABLE FOR USE

OWNER	TAG NUMBER	TANK DESCRIPTION	VOLUME (BBL)	VOLUME (GAL)	CONTENTS	FABRICATION DATE	CONSTRUCTION STANDARD	EXTERNAL INSPECTION SCHEDULE, LAST; NEXT	INTERNAL INSPECTION SCHEDULE, LAST; NEXT	SERVICE HISTORY	COMMENTS
Rain for Rent	239578	Bi-Level Tiger Tank			Oil; drilling fluids	1995	RFR Spec. 99044	2012; 2017	2012; 2022	Continuous since 1998	CPAI Ref# SST-024
Rain for Rent	254254	Bi-Level Tiger Tank			Varies	1999	RFR Spec. 99044	2012; 2017	2012; 2022	Continuous since 1999	
Rain for Rent	254438	Bi-Level Tiger Tank			Oil; drilling fluids	1999	RFR Spec. 99044	2008; 2013	2002; 2012	Continuous since 1999	Not in use at CPAI facilities
Rain for Rent	254439	Bi-Level Tiger Tank			Oil; drilling fluids	1999	RFR Spec. 99044	2008; 2013	2002; 2012	Continuous since 1999	Not in use at CPAI facilities
Rain for Rent	254440	Bi-Level Tiger Tank			Oil; drilling fluids	1999	RFR Spec. 99044	2012; 2017	2012; 2022	Continuous since 1999	
Rain for Rent	254441	Bi-Level Tiger Tank			Oil; drilling fluids	1999	RFR Spec. 99044	2012; 2017	2012; 2022	Continuous since 1999	
Rain for Rent	254456	Bi-Level Tiger Tank			Oil; drilling fluids	1999	RFR Spec. 99044	2012; 2017	2012; 2022	Continuous since 1999	
Rain for Rent	254465	Bi-Level Tiger Tank			Varies	1999	RFR Spec. 99044	2007; 2012	2002; 2012	Continuous since 1999	CPAI Ref# SST-047 Not in use at CPAI facilities
Rain for Rent	254605	Bi-Level Tiger Tank			Varies	2000	RFR Spec. 99044	2008; 2013	2006; 2016	Continuous since 2000	Not in use at CPAI facilities
Rain for Rent	254615	Bi-Level Tiger Tank			Varies	2000	RFR Spec. 99044	2008; 2013	2002; 2012	Continuous since 2000	Not in use at CPAI facilities
Rain for Rent	254881	Bi-Level Tiger Tank			Varies	2000	RFR Spec. 99044	2008; 2013	2002; 2012	Continuous since 2000	Not in use at CPAI facilities
Rain for Rent	254883	Bi-Level Tiger Tank			Varies	2002	RFR Spec. 99044	2007; 2012	2002; 2012	Continuous since 2002	CPAI Ref# SST-048 Not in use at CPAI facilities
Rain for Rent	254925	Bi-Level Tiger Tank			Varies	2000	RFR Spec. 99044	2009; 2014	2002; 2012	Continuous since 2000	Not in use at CPAI facilities
Rain for Rent	254980	Bi-Level Tiger Tank			Oil; drilling fluids	2000	RFR Spec. 99044	2012; 2017	2012; 2022	Continuous since 2000	CPAI Ref# SST-026

TABLE B-3
RENTED OR LEASED PORTABLE ADEC REGULATED OIL STORAGE TANKS AVAILABLE FOR USE

OWNER	TAG NUMBER	TANK DESCRIPTION	VOLUME (BBL)	VOLUME (GAL)	CONTENTS	FABRICATION DATE	CONSTRUCTION STANDARD	EXTERNAL INSPECTION SCHEDULE, LAST; NEXT	INTERNAL INSPECTION SCHEDULE, LAST; NEXT	SERVICE HISTORY	COMMENTS
Rain for Rent	254993	Bi-Level Tiger Tank			Varies	2000	RFR Spec. 99044	2008;2013	2002; 2012	Continuous since 2000	Not in use at CPAI facilities
Rain for Rent	255129	Bi-Level Tiger Tank			Varies	2001	RFR Spec. 99044	2009; 2014	2002; 2012	Continuous since 2001	Not in use at CPAI facilities
Rain for Rent	255132	Bi-Level Tiger Tank			Varies	2001	RFR Spec. 99044	2007; 2012	2002; 2012	Continuous since 2001	Not in use at CPAI facilities
Rain for Rent	255134	Bi-Level Tiger Tank			Varies	2001	RFR Spec. 99044	2009; 2014	2002; 2012	Continuous since 2001	Not in use at CPAI facilities
Rain for Rent	255141	Bi-Level Tiger Tank			Varies	2001	RFR Spec. 99044	2008; 2013	2002; 2012	Continuous since 2001	Not in use at CPAI facilities
Rain for Rent	255169	Bi-Level Tiger Tank			Varies	2001	RFR Spec. 99044	2008; 2013	2002; 2012	Continuous since 2001	Not in use at CPAI facilities
Rain for Rent	255286	Bi-Level Tiger Tank			Oil; drilling fluids	2001	RFR Spec. 99044	2008; 2013	2008; 2012	Continuous since 2001	Not in use at CPAI facilities
Rain for Rent	255317	Bi-Level Tiger Tank			Oil; drilling fluids	2001	RFR Spec. 99044	2012; 2017	2012; 2022	Continuous since 2001	CPAI Ref# SST-023
Rain for Rent	255400	Bi-Level Tiger Tank			Varies	2002	RFR Spec. 99044	2007; 2012	2002; 2012	Continuous since 2002	CPAI Ref# SST-046 Not in use at CPAI facilities
Rain for Rent	255413	Bi-Level Tiger Tank			Oil; drilling fluids	2001	RFR Spec. 99044	2012; 2017	2012; 2022	Continuous since 2001	
Rain for Rent	255415	Bi-Level Tiger Tank			Oil; drilling fluids	2001	RFR Spec. 99044	2012; 2017	2012; 2022	Continuous since 2001	
Rain for Rent	255497	Bi-Level Tiger Tank			Oil; drilling fluids	2001	RFR Spec. 99044	2012; 2017	2004; 2014	Continuous since 2001	CPAI Ref# SST-022
Rain for Rent	255532	Bi-Level Tiger Tank			Oil; drilling fluids	2001	RFR Spec. 99044	2008; 2013	2002; 2012	Continuous since 2001	Not in use at CPAI facilities
Rain for Rent	255536	Bi-Level Tiger Tank			Varies	2001	RFR Spec. 99044	2009; 2014	2002; 2012	Continuous since 2001	Not in use at CPAI facilities

TABLE B-3
RENTED OR LEASED PORTABLE ADEC REGULATED OIL STORAGE TANKS AVAILABLE FOR USE

OWNER	TAG NUMBER	TANK DESCRIPTION	VOLUME (BBL)	VOLUME (GAL)	CONTENTS	FABRICATION DATE	CONSTRUCTION STANDARD	EXTERNAL INSPECTION SCHEDULE, LAST; NEXT	INTERNAL INSPECTION SCHEDULE, LAST; NEXT	SERVICE HISTORY	COMMENTS
Rain for Rent	255548	Bi-Level Tiger Tank			Varies	2001	RFR Spec. 99044	2008; 2013	2002; 2012	Continuous since 2001	Not in use at CPAI facilities
Rain for Rent	255568	Bi-Level Tiger Tank			Varies	2002	RFR Spec. 99044	2007; 2012	2002; 2012	Continuous since 2002	Not in use at CPAI facilities
Rain for Rent	255574	Bi-Level Tiger Tank			Varies	2002	RFR Spec. 99044	2008; 2013	2002; 2012	Continuous since 2002	Not in use at CPAI facilities
Rain for Rent	255576	Bi-Level Tiger Tank			Varies	2002	RFR Spec. 99044	2007; 2012	2002; 2012	Continuous since 2002	CPAI Ref# SST-049 Not in use at CPAI facilities
Rain for Rent	255902	Bi-Level Tiger Tank			Varies	2006	RFR Spec. 107789	2010; 2015	2010; 2020	Continuous since 2006	
Rain for Rent	258119	Tiger Tank			Varies	2000	RFR Spec. 99044	2008; 2013	2008; 2010	Continuous since 2000	Not in use at CPAI facilities
Rain for Rent	258670	Bi-Level Tiger Tank			Varies	2002	RFR Spec. 107789	2010; 2015	2010; 2020	Continuous since 2002	
Rain for Rent	259172	Bi-Level Tiger Tank			Varies	2004	RFR Spec. 107789	2010; 2015	2010; 2020	Continuous since 2004	
Rain for Rent	259408	Bi-Level Tiger Tank			Varies	2004	RFR Spec. 107789	2010; 2015	2010; 2020	Continuous since 2004	
Rain for Rent	259412	Bi-Level Tiger Tank			Varies	2004	RFR Spec. 107789	2010; 2015	2010; 2020	Continuous since 2004	
Rain for Rent	265402	Bi-Level Tiger Tank			Varies	2006	RFR Spec. 107789	2010; 2015	2010; 2020	Continuous since 2006	
Rain for Rent	266010	Tiger Tank			Varies	2008	RFR Spec. 99044	New 2008; 2013	New 2008; 2018	New 2008	Not in use at CPAI facilities
TANKO Alaska	108	Double-wall, welded steel			Oil; drilling fluids	1983	None	2010; 2015	2005; 2015	Continuous since 1983	
TANKO Alaska	111	Double-wall, welded steel			Varies	1983	None	2010; 2015	2010; 2015	Continuous since 1983	CPAI Ref# SST-068

TABLE B-3
RENTED OR LEASED PORTABLE ADEC REGULATED OIL STORAGE TANKS AVAILABLE FOR USE

OWNER	TAG NUMBER	TANK DESCRIPTION	VOLUME (BBL)	VOLUME (GAL)	CONTENTS	FABRICATION DATE	CONSTRUCTION STANDARD	EXTERNAL INSPECTION SCHEDULE, LAST; NEXT	INTERNAL INSPECTION SCHEDULE, LAST; NEXT	SERVICE HISTORY	COMMENTS
TANKO Alaska	114	Double-wall, welded steel			Oil; drilling fluids	1983	None	2010; 2015	2005; 2015	Continuous since 1983	
TANKO Alaska	115	Double-wall, welded steel			Oil; drilling fluids	1983	None	2010; 2015	2010; 2015	Continuous since 1983	
TANKO Alaska	116	Double-wall, welded steel			Oil; drilling fluids	1983	None	2010; 2015	2010; 2015	Continuous since 1992	CPAI Ref# SST-030
TANKO Alaska	117	Double-wall, welded steel			Oil; drilling fluids	1983	None	2010; 2015	2010; 2015	Continuous since 1992	CPAI Ref# SST-031
TANKO Alaska	118	Double-wall, welded steel			Oil; drilling fluids	1983	None	2010; 2015	2010; 2015	Continuous since 1992	CPAI Ref# SST-032
TANKO Alaska	119	Double-wall, welded steel			Oil; drilling fluids	1983	None	2010; 2015	2010; 2015	Continuous since 1992	CPAI Ref# SST-033
TANKO Alaska	121	Double-wall, welded steel			Oil; drilling fluids	1983	None	2010; 2015	2010; 2015	Continuous since 1992	CPAI Ref# SST-034
TANKO Alaska	122	Double-wall, welded steel			Oil; drilling fluids	1983	None	2009; 2012	2009; 2012	Continuous since 1992	Not in use at CPAI facilities
TANKO Alaska	123	Double-wall, welded steel			Oil; drilling fluids	1983	None	2010; 2015	2010; 2015	Continuous since 1983	
TANKO Alaska	124	Double-wall, welded steel			Oil; drilling fluids	1983	None	2010; 2015	2010; 2015	Continuous since 1983	CPAI Ref# SST-051
TANKO Alaska	125	Double-wall, welded steel			Oil; drilling fluids	1983	None	2010; 2015	2010; 2015	Continuous since 1983	CPAI Ref# SST-052
TANKO Alaska	127	Double-wall, welded steel			Oil; drilling fluids	1983	None	2010; 2015	2010; 2015	Continuous since 1992	
TANKO Alaska	128	Double-wall, welded steel			Oil; drilling fluids	1983	None	2010; 2015	2010; 2015	Continuous since 1983	CPAI Ref# SST-053
TANKO Alaska	130	Double-wall, welded steel			Oil; drilling fluids	1983	None	2010; 2015	2010; 2015	Continuous since 1983	

TABLE B-3
RENTED OR LEASED PORTABLE ADEC REGULATED OIL STORAGE TANKS AVAILABLE FOR USE

OWNER	TAG NUMBER	TANK DESCRIPTION	VOLUME (BBL)	VOLUME (GAL)	CONTENTS	FABRICATION DATE	CONSTRUCTION STANDARD	EXTERNAL INSPECTION SCHEDULE, LAST; NEXT	INTERNAL INSPECTION SCHEDULE, LAST; NEXT	SERVICE HISTORY	COMMENTS
TANKO Alaska	131	Double-wall, welded steel			Varies	1983	None	2010; 2015	2010; 2015	Continuous since 1983	CPAI Ref# SST-069
TANKO Alaska	132	Double-wall, welded steel			Oil; drilling fluids	1983	None	2010; 2015	2010; 2015	Continuous since 1983	
TANKO Alaska	H-01	Single-wall upright			Varies	1992	None	2011; 2016	2011; 2016	Continuous since 1992	CPAI Ref# SST-036
TANKO Alaska	H-02	Single-wall upright			Varies	1992	None	2011; 2016	2011; 2016	Continuous since 1992	CPAI Ref # SST-037
TANKO Alaska	H-03	Single-wall upright			Varies	1992	None	2011; 2016	2011; 2016	Continuous since 1992	CPAI Ref# SST-038
TANKO Alaska	H-04	Single-wall upright			Varies	1992	None	2011; 2016	2011; 2016	Continuous since 1992	CPAI Ref# SST-039
TANKO Alaska	H-05	Single-wall upright			Varies	1992	None	2011; 2016	2011; 2016	Continuous since 1992	CPAI Ref# SST-040
TANKO Alaska	H-06	Single-wall upright			Varies	1992	None	2011; 2016	2011; 2016	Continuous since 1992	CPAI Ref# SST-041
TANKO Alaska	H-07	Single-wall upright			Varies	1992	None	2011; 2016	2011; 2016	Continuous since 1992	CPAI Ref# SST-042
TANKO Alaska	H-08	Single-wall upright			Varies	1992	None	2011; 2016	2011; 2016	Continuous since 1992	CPAI Ref# SST-043
TANKO Alaska	O-1 (CTU-01)	Double-wall; Horizontal open-top			Varies	1990	None	2008; 2013	2008; 2013	Continuous since 1990	CPAI Ref# SST-054 Not in use at CPAI facilities
TANKO Alaska	O-10	Single-wall Open Top Skid			Varies	Unknown	None	2010; 2015	2010; 2015	Continuous	
TANKO Alaska	O-11	Single-wall Open Top Skid			Varies	Unknown	None	2010; 2015	2010; 2015	Continuous	
TANKO Alaska	O-15	Tiger Tank			Varies	1986	None	2010; 2015	2010; 2015	Continuous since 1990	CPAI Ref# SST-057

TABLE B-3
RENTED OR LEASED PORTABLE ADEC REGULATED OIL STORAGE TANKS AVAILABLE FOR USE

OWNER	TAG NUMBER	TANK DESCRIPTION	VOLUME (BBL)	VOLUME (GAL)	CONTENTS	FABRICATION DATE	CONSTRUCTION STANDARD	EXTERNAL INSPECTION SCHEDULE, LAST; NEXT	INTERNAL INSPECTION SCHEDULE, LAST; NEXT	SERVICE HISTORY	COMMENTS
TANKO Alaska	O-16	Tiger Tank			Varies	1986	None	2010; 2015	2010; 2015	Continuous since 1990	CPAI Ref# SST-058
TANKO Alaska	O-17	Tiger Tank			Varies	Pre-1990	None	2010; 2015	2010; 2015	Continuous since 1990	CPAI Ref# SST-044
TANKO Alaska	O-18	Horizontal open-top			Varies	Pre-1990	None	2011; 2016	2011; 2016	Continuous since 1990	CPAI Ref# SST-059
TANKO Alaska	O-21	Tiger Tank			Varies	1986	None	2011; 2016	2011; 2016	Continuous since 1990	CPAI Ref# SST-045
TANKO Alaska	O-22	Tiger Tank			Varies	1986	None	2011; 2016	2011; 2016	Continuous since 1990	
TANKO Alaska	O-23	Tiger Tank			Varies	1986	None	2011; 2016	2011; 2016	Continuous since 1990	
TANKO Alaska	O-24	Horizontal open-top			Varies	Pre-1990	None	2011; 2016	2011; 2016	Continuous since 1990	CPAI Ref# SST-060
TANKO Alaska	O-3 (CTU-03)	Double-wall; Horizontal open-top			Varies	1990	None	2010; 2015	2010; 2015	Continuous since 1990	
TANKO Alaska	O-5 (CTU-05)	Double-wall; Horizontal open-top			Varies	1990	None	2013; 2018	2013; 2018	Continuous since 1990	
TANKO Alaska	O-8 (CTU-08)	Double-wall; Horizontal open-top			Varies	1992	None	2011; 2016	2011; 2016	Continuous since 1992	CPAI Ref# SST-055
TANKO Alaska	O-9 (CTU-09)	Double-wall; Horizontal open-top			Varies	1992	None	2011; 2016	2011; 2016	Continuous since 1992	CPAI Ref# SST-056
TANKO Alaska	T-12	Tiger Tank			Varies	Pre-1992	None	2011; 2016	2011; 2016	Continuous since 1992	
TANKO Alaska	T-14	Tiger Tank			Oil; drilling fluids	In service pre-1992	None	2010; 2015	2010; 2015	Continuous since 1992	
TANKO Alaska	T-18	Tiger Tank			Varies	1990	None	2010; 2015	2010; 2015	Continuous since 1990	

TABLE B-3
RENTED OR LEASED PORTABLE ADEC REGULATED OIL STORAGE TANKS AVAILABLE FOR USE

OWNER	TAG NUMBER	TANK DESCRIPTION	VOLUME (BBL)	VOLUME (GAL)	CONTENTS	FABRICATION DATE	CONSTRUCTION STANDARD	EXTERNAL INSPECTION SCHEDULE, LAST; NEXT	INTERNAL INSPECTION SCHEDULE, LAST; NEXT	SERVICE HISTORY	COMMENTS
TANKO Alaska	T-19	Tiger Tank			Varies	1990	None	2010; 2015	2010; 2015	Continuous since 1990	
TANKO Alaska	T-20	Tiger Tank			Varies	1990	None	2010; 2015	2010; 2015	Continuous since 1990	
TANKO Alaska	T-21	Tiger Tank			Varies	1990	None	2010; 2015	2010; 2015	Continuous since 1990	
TANKO Alaska	T-22	Double-wall Horizontal Open-top			Drilling fluids	2014	ADEC Approval #2014-01	New; 2019	New; 2019	New 2014	See letter dated 10/27/2014 in Section 2.6
TANKO Alaska	T-23	Double-wall Horizontal Open-top			Drilling fluids	2014	ADEC Approval #2014-01	New; 2019	New; 2019	New 2014	See letter dated 10/27/2014 in Section 2.6
TANKO Alaska	T-24	Double-wall Horizontal Open-top			Drilling fluids	2014	ADEC Approval #2014-01	New; 2019	New; 2019	New 2014	See letter dated 10/27/2014 in Section 2.6
TANKO Alaska	T-25	Double-wall Horizontal Open-top			Drilling fluids	2014	ADEC Approval #2014-01	New; 2019	New; 2019	New 2014	See letter dated 10/27/2014 in Section 2.6
TANKO Alaska	T-26	Double-wall Horizontal Open-top			Drilling fluids	2014	ADEC Approval #2014-01	New; 2019	New; 2019	New 2014	See letter dated 10/27/2014 in Section 2.6
TANKO Alaska	T-27	Double-wall Horizontal Open-top			Drilling fluids	2014	ADEC Approval #2014-01	New; 2019	New; 2019	New 2014	See letter dated 10/27/2014 in Section 2.6
TANKO Alaska	T-28	Double-wall Horizontal Open-top			Drilling fluids	2014	ADEC Approval #2014-01	New; 2019	New; 2019	New 2014	See letter dated 10/27/2014 in Section 2.6
TANKO Alaska	T-29	Double-wall Horizontal Open-top			Drilling fluids	2014	ADEC Approval #2014-01	New; 2019	New; 2019	New 2014	See letter dated 10/27/2014 in Section 2.6
TANKO Alaska	T-30	Double-wall Horizontal Open-top			Drilling fluids	2014	ADEC Approval #2014-01	New; 2019	New; 2019	New 2014	See letter dated 10/27/2014 in Section 2.6
TANKO Alaska	T-31	Double-wall Horizontal Open-top			Drilling fluids	2014	ADEC Approval #2014-01	New; 2019	New; 2019	New 2014	See letter dated 10/27/2014 in Section 2.6
TANKO Alaska	T-32	Double-wall Horizontal Open-top			Drilling fluids	2014	ADEC Approval #2014-01	New; 2019	New; 2019	New 2014	See letter dated 10/27/2014 in Section 2.6

TABLE B-3
RENTED OR LEASED PORTABLE ADEC REGULATED OIL STORAGE TANKS AVAILABLE FOR USE

OWNER	TAG NUMBER	TANK DESCRIPTION	VOLUME (BBL)	VOLUME (GAL)	CONTENTS	FABRICATION DATE	CONSTRUCTION STANDARD	EXTERNAL INSPECTION SCHEDULE, LAST; NEXT	INTERNAL INSPECTION SCHEDULE, LAST; NEXT	SERVICE HISTORY	COMMENTS
TANKO Alaska	T-33	Double-wall Horizontal Open-top			Drilling fluids	2014	ADEC Approval #2014-01	New; 2019	New; 2019	New 2014	See letter dated 10/27/2014 in Section 2.6

Notes

1. Listed tanks are not owned by CPAI, but may be directly rented or leased by CPAI. Owners are responsible for conducting appropriate inspections and for maintaining records according to the provisions of 18 AAC 75.066. Tanks leased (rented) directly
2. Tanks are required to be placed in secondary containment sized to 100% of the volume of the largest tank, plus additional volume for local precipitation, per 18 AAC 75.075(a). A compliance waiver must be in place for tanks that do not meet this
3. CPAI is responsible for ensuring tanks meet regulatory requirements for leak detection systems, overfill protection, and testing of overfill protection per 18 AAC 75.066 as described in this ODPCP.
4. Tanks placed into service after December 30, 2008 must be constructed and installed in compliance with 18 AAC 75.066.
5. Tanks placed into service before December 30, 2008 do not require ADEC approval of construction standard. Prior to use, tank records are reviewed by CPAI to determine the service history.

TABLE B-4
THIRD-PARTY ADEC REGULATED OIL STORAGE TANKS NOT OWNED OR OPERATED BY CPAI

OWNER	TAG NUMBER	TANK DESCRIPTION	VOLUME (BBL)	VOLUME (GAL)	CONTENTS	FABRICATION DATE	CONSTRUCTION STANDARD	EXTERNAL INSPECTION SCHEDULE, LAST; NEXT	INTERNAL INSPECTION SCHEDULE, LAST; NEXT	COMMENTS
Doyon	19-001	Steel Horizontal Tank			Diesel	Unknown	Unknown	2013; 2018	2008; 2018	Located on Doyon 19 Drill Rig
MI Swaco	E-02-034-S1	Upright Tank (MI 32)			Drilling Fluids	2002	API 12 F	2012; 2017	2012; 2022	Located at Alpine (CD-1)
MI Swaco	E-02-034-S2	Upright Tank (MI 34)			Drilling Fluids	2002	API 650	2011; 2016	2011; 2021	Located at Alpine (CD-1)
MI Swaco	E-02-034-S3	Upright Tank (MI 33)			Drilling Fluids	2002	API 650	2011; 2016	2011; 2021	Located at Alpine (CD-1)
MI Swaco	E-98-272-2	Upright Tank (MI 27)			Drilling Fluids	1998	API 12 F	2013; 2018	2008; 2018	Located at Alpine (CD-1)
MI Swaco	E-98-272-3	Upright Tank (MI 28)			Drilling Fluids	1998	API 12 F	2013; 2018	2008; 2018	Located at Alpine (CD-1)
MI Swaco	E-98-272-4	Upright Tank (MI 26)			Drilling Fluids	1998	API 12 F	2013; 2015	2008; 2013	Located at Alpine (CD-1)
MI Swaco	E-98-272-5	Upright Tank (MI 30)			Drilling Fluids	1998	API 12 F	2013; 2018	2008; 2018	Located at Alpine (CD-1)
MI Swaco	E-98-272-6	Upright Tank (MI 31)			Drilling Fluids	1998	API 12 F	2013; 2018	2008; 2018	Located at Alpine (CD-1)
MI Swaco	T-03	Horizontal			Varies	Prior to 2004	Unknown	2010; 2015	2010; 2020	
MI Swaco	T-04	Horizontal			Varies	Prior to 2004	Unknown	2010; 2015	2010; 2020	
MI Swaco	T-20451	Upright Tank MI A6061594			Slurry	2009	API 650 Appendix J	New 2009; 2014	New 2009; 2019	Located at MI SWACO CRI Unit
MI Swaco	T-20452	Upright Tank MI A6061595			Slurry	2009	API 650 Appendix J	New 2009; 2014	New 2009; 2019	Located at MI SWACO CRI Unit
MI Swaco	T-0001	Upright Tank MI A0573826			Drilling Fluids	2009	API 650 Appendix J	New 2009; 2014	New 2009; 2019	Located at MI SWACO CRI Unit
MI Swaco	T-0002	Upright Tank MI A0573827			Drilling Fluids	2009	API 650 Appendix J	New 2009; 2014	New 2009; 2019	Located at MI SWACO CRI Unit
MI Swaco	T-0003	Upright Tank MI A0573828			Drilling Fluids	2009	API 650 Appendix J	New 2009; 2014	New 2009; 2019	Located at MI SWACO CRI Unit
MI Swaco	T-0004	Upright Tank MI A0573829			Drilling Fluids	2009	API 650 Appendix J	New 2009; 2014	New 2009; 2019	Located at MI SWACO CRI Unit
MI Swaco	T-0005	Upright Tank MI A0573830			Drilling Fluids	2009	API 650 Appendix J	New 2009; 2014	New 2009; 2019	Located at MI SWACO CRI Unit
MI Swaco	T-0006	Upright Tank MI A0573831			Drilling Fluids	2009	API 650 Appendix J	New 2009; 2014	New 2009; 2019	Located at MI SWACO CRI Unit
Nordic Calista	73080	Double-Wall Tank			Miscellaneous Hydrocarbons	Unknown	Unknown	2008; 2011	2008; 2011	Located on Nordic 2 Rig
Schlumberger	2SUS15522	Tiger Tank			Varies	2000	ADEC Waiver	2011; 2016	2011; 2021	ADEC Waiver on File Section 2.6

TABLE B-4
THIRD-PARTY ADEC REGULATED OIL STORAGE TANKS NOT OWNED OR OPERATED BY CPAI

OWNER	TAG NUMBER	TANK DESCRIPTION	VOLUME (BBL)	VOLUME (GAL)	CONTENTS	FABRICATION DATE	CONSTRUCTION STANDARD	EXTERNAL INSPECTION SCHEDULE, LAST; NEXT	INTERNAL INSPECTION SCHEDULE, LAST; NEXT	COMMENTS
Schlumberger	2SUS15582	Tiger Tank			Varies	2000	ADEC Waiver	2011; 2016	2011; 2021	ADEC Waiver on File Section 2.6
Schlumberger	2SUS15818	Tiger Tank			Varies	2000	ADEC Waiver	2013; 2018	2013; 2023	ADEC Waiver on File Section 2.6
Schlumberger	2SUS15873	Tiger Tank			Varies	2000	ADEC Waiver	2011; 2016	2011; 2021	ADEC Waiver on File Section 2.6
Schlumberger	2SUS16104	Tiger Tank			Varies	2000	ADEC Waiver	2008; 2013	2008; 2018	ADEC Waiver on File Section 2.6
Schlumberger	2SUS16105	Tiger Tank			Varies	2000	ADEC Waiver	2011; 2016	2011; 2021	ADEC Waiver on File Section 2.6
Schlumberger	2SUS16106	Tiger Tank			Varies	2000	ADEC Waiver	2011; 2016	2011; 2021	ADEC Waiver on File Section 2.6
Schlumberger	2SUS18471	Horizontal rectangular			Varies	2001	ADEC Waiver	2011; 2016	2011; 2021	ADEC Waiver on File Section 2.6
Schlumberger	2SUS18472	Horizontal rectangular			Varies	2001	ADEC Waiver	2011; 2016	2011; 2021	ADEC Waiver on File Section 2.6
Schlumberger	2SUS18473	Horizontal rectangular			Varies	2001	ADEC Waiver	2008; 2013	2008; 2018	ADEC Waiver on File Section 2.6
Schlumberger	2SUS18474	Horizontal rectangular			Varies	2001	ADEC Waiver	2011; 2016	2011; 2021	ADEC Waiver on File Section 2.6
Schlumberger	2SUS18475	Horizontal rectangular			Varies	2001	ADEC Waiver	2012; 2014	2012; 2022	ADEC Waiver on File Section 2.6
Schlumberger	2SUS18476	Horizontal rectangular			Varies	2001	ADEC Waiver	2012; 2017	2012; 2022	ADEC Waiver on File Section 2.6
Schlumberger	2SUS18477	Horizontal rectangular			Varies	2001	ADEC Waiver	2011; 2016	2011; 2021	ADEC Waiver on File Section 2.6
Schlumberger	2SUS18478	Horizontal rectangular			Varies	2001	ADEC Waiver	2011; 2016	2011; 2021	ADEC Waiver on File Section 2.6
Schlumberger	2SUS18479	Horizontal rectangular			Varies	2001	ADEC Waiver	2012; 2017	2012; 2022	ADEC Waiver on File Section 2.6
Schlumberger	2SUS18480	Horizontal rectangular			Varies	2001	ADEC Waiver	2012; 2017	2012; 2022	ADEC Waiver on File Section 2.6
Schlumberger	2SUS18601	Tiger Tank			Varies	2001	ADEC Waiver	2012; 2017	2012; 2022	ADEC Waiver on File Section 2.6
Schlumberger	2SUS18603	Tiger Tank			Varies	2001	ADEC Waiver	2008; 2013	2008; 2018	ADEC Waiver on File Section 2.6
Schlumberger	2SUS18604	Tiger Tank			Varies	2000	ADEC Waiver	2011; 2016	2011; 2021	ADEC Waiver on File Section 2.6
Schlumberger	2SUS18605	Tiger Tank			Varies	2000	ADEC Waiver	2011; 2016	2011; 2021	ADEC Waiver on File Section 2.6
Schlumberger	2SUS18606	Tiger Tank			Varies	2001	ADEC Waiver	2008; 2013	2008; 2018	ADEC Waiver on File Section 2.6

TABLE B-4
THIRD-PARTY ADEC REGULATED OIL STORAGE TANKS NOT OWNED OR OPERATED BY CPAI

OWNER	TAG NUMBER	TANK DESCRIPTION	VOLUME (BBL)	VOLUME (GAL)	CONTENTS	FABRICATION DATE	CONSTRUCTION STANDARD	EXTERNAL INSPECTION SCHEDULE, LAST; NEXT	INTERNAL INSPECTION SCHEDULE, LAST; NEXT	COMMENTS
Schlumberger	2SUS18607	Tiger Tank			Varies	2001	ADEC Waiver	2013; 2018	2013; 2023	ADEC Waiver on File Section 2.6
Schlumberger	2SUS18608	Tiger Tank			Varies	2000	ADEC Waiver	2011; 2016	2011; 2021	ADEC Waiver on File Section 2.6
Schlumberger	2SUS18665	Tiger Tank			Varies	2001	ADEC Waiver	2012; 2017	2012; 2022	ADEC Waiver on File Section 2.6
Schlumberger	2SSF41956	Horizontal rectangular			Varies	2012	ADEC Approval #2013-01	New 2012; 2017	New 2012; 2022	See ADEC approval in Section 2.6
Schlumberger	2SSF41957	Horizontal rectangular			Varies	2012	ADEC Approval #2013-01	New 2012; 2017	New 2012; 2022	See ADEC approval in Section 2.6
Schlumberger	2SSF41958	Horizontal rectangular			Varies	2012	ADEC Approval #2013-01	New 2012; 2017	New 2012; 2022	See ADEC approval in Section 2.6
Schlumberger	2SSF41959	Horizontal rectangular			Varies	2012	ADEC Approval #2013-01	New 2012; 2017	New 2012; 2022	See ADEC approval in Section 2.6
Schlumberger	2SSF41960	Horizontal rectangular			Varies	2012	ADEC Approval #2013-01	New 2012; 2017	New 2012; 2022	See ADEC approval in Section 2.6
Schlumberger	2SFF41961	Horizontal rectangular Frac Tank			Varies	2013	ADEC Approval #2013-01	New 2013; 2018	New 2013; 2023	See ADEC approval in Section 2.6
Schlumberger	2SFF41962	Horizontal rectangular Frac Tank			Varies	2013	ADEC Approval #2013-01	New 2013; 2018	New 2013; 2023	See ADEC approval in Section 2.6
Schlumberger	2SFF41963	Horizontal rectangular Frac Tank			Varies	2013	ADEC Approval #2013-01	New 2013; 2018	New 2013; 2023	See ADEC approval in Section 2.6
Schlumberger	2SFF41964	Horizontal rectangular Frac Tank			Varies	2013	ADEC Approval #2013-01	New 2013; 2018	New 2013; 2023	See ADEC approval in Section 2.6

Note: Prior to return to use at CPAI facilities, tank requires current inspection, record review under CPAI's tank management program, and update of information in this table (subject tanks shown with inspection dates in gray cells). Listed tanks are not owned by CPAI. Owners are responsible for conducting appropriate inspections and for maintaining records according to the provisions of 18 AAC 75.066.

APPENDIX C:

KUPARUK SPILL HISTORY

TABLE C-1
KUPARUK SPILL HISTORY

Spill #	Date	Location	Volume (Gal)	Product	Cause Explanation	Source	Corrective Action
KR-0125401	6/1/1985	WSAK	255	Crude-100%	TBD - Expected contamination from 1985/1986 operation of West Sak Pilot Project. Suspected sump overflow. Discovered when removing pylons for Module move.	Sumps	--
KR-8600302	1/3/1986	2X	126	Crude-90%, Diesel-5%, Arine-5%	While flowing well pressure and fluid a burp of gas blew fluid out	Compressor Vents/ Module Vents	None
KR-8602301	1/23/1986	1C	210	Crude-50%, Diesel-50%	Valve frozen steaming valve to thaw when it broke loose	Fittings/Seals/ Connections	Caution operator to make sure valves are closed before a hose is removed.
KR-8603001	1/30/1986	2Z	126	Crude-50%, Diesel-50%	Pumped hot diesel into flowline and thawed partially opened valve	Pipe/Flowlines/ Hardline	Valve shut on tank and plugged off with bull plug.
KR-8604501	2/14/1986	ROAD	294	Diesel-100%	Hot oil unit traveling from 1y shop to cpf1 pump on unit engaged	Pumps	We are checking on reasons why the pump engaged.
KR-8604801	2/17/1986	CPF3	315	Diesel-100%	Gasket failure	Fittings/Seals/ Connections	Changed Gasket
KR-8604802	2/17/1986	WSAK	84	Crude-10%, Produced Water-90%	Vac truck offloading when king nipple came out of end of hose	Transfer Hoses	The banding securing the king nipple in the hose had been improperly installed. All of our hoses will be inspected and replaced if this is the case.
KR-8606301	3/4/1986	WSAK	70	Gelled Diesel-100%	Circulation of tank contents for mixing splashed out manway in tank	Tanks	Reduced level in tank.
KR-8606901	3/10/1986	2V	378	Crude-100%	Operator clearing snow from between wells and broke a test line	Pipe/Flowlines/ Hardline	Coordination meeting to ensure better communication between agencies in the future.
KR-8607902	3/20/1986	1E	504	Produced Water-50%, Methanol-50%	Mixture leaked out of tank flowback valve on wellhead riser left open	Pipe/Flowlines/ Hardline	Valves will be double checked before starting.
KR-8607901	3/20/1986	ROAD	84	Diesel-100%	Diesel sprayed thru bleed valve during nitrogen purge (y intersection)	Fittings/Seals/ Connections	Provide a tank to act as a separator, perhaps reduce the velocity of the purge.
KR-8608602	3/27/1986	WSAK	252	Crude-50%, Produced Water-50%	Prod water overflowed slop oil tank into lined dike area	Tanks	Slop oil tank level will be checked more frequently.
KR-8609801	4/8/1986	ROAD	700	Arctic Diesel-100%	Hammer lock clamps on diesel line burst (int of 3n & Oliktok)	Transfer Hoses	Hard pipe will be used as "filling line" instead of rubber hose. Better positioning and insulation for the hose will be utilized.
KR-8609902	4/9/1986	3F	105	Crude-100%	1/2" s.s tbg fitting improperly installed	Transfer Hoses	W.O.W. to have similar fitting checked.

TABLE C-1 (CONTINUED): KUPARUK SPILL HISTORY

Spill #	Date	Location	Volume (Gal)	Product	Cause Explanation	Source	Corrective Action
KR-8610001	4/10/1986	3N	200	Diesel-100%	Hose on discharge side of a craig taylor transfer pump ruptured	Transfer Hoses	A ball valve has been installed on the intake side of the pump to ensure shut down in the event of another mishap.
KR-8610101	4/11/1986	3J	126	Diesel-100%	While filling flowline diesel spilled needle valve on tree cap left op	Fittings/Seals/ Connections	Better communication between Arco and personnel contract personnel.
KR-8610801	4/18/1986	2F	210	Produced Water-40%, Glycol-60%	Rupture disc on line heater failed	Fittings/Seals/ Connections	A new design for the ruptured disc.
KR-8611002	4/20/1986	CPF1	168	Crude-50%, Produced Water-50%	Oily water leaked n ground under tank-tank bridle not prepared for maintenance.	Tanks	Additional training of operators and maintenance personnel.
KR-8612101	5/1/1986	1E	84	Diesel-100%	Rear compartment of tank truck overflowed while unloading hydrotest	Heavy Equip/Mobile Equip/Vehicles	Don't unload directly into tank. Flow must go through filter and riser. If the filter is plugged, make the trucks wait until it can be cleaned.
KR-8613101	5/11/1986	CPF2	84	Crude-100%	Bleed valve on bottom flow line to b divert tank leaked	Fittings/Seals/ Connections	Tighten bull plug in drain valve.
KR-8614101	5/21/1986	3J	210	Diesel-100%	After post frac-coil tbg cleanout sand ops while coil tbg parted	Coiled Tubing Unit/ Wireline Equip	Periodically press test coil tubing- visual inspection after each coil TBG usage.
KR-8614501	5/25/1986	1E	210	Gelled Diesel-100%	Offloading vac truck hose blew off king nipple	Transfer Hoses	Going to do an inspection of the hoses on the vac trucks and diesel tankers.
KR-8615101	5/31/1986	WSAK	210	Crude-70%, Other-30%	Driver moved truck and hose parted and tank on ground spilled fluid	Transfer Hoses	Driver was reprimanded and will be more careful.
KR-8621201	7/31/1986	FUEL	100	Diesel-100%	Truck at loading dock had valve failure	Fittings/Seals/ Connections	Valve on tanker has been repaired. Driver has been reinstructed.
KR-8622401	8/12/1986	2Z	84	Crude-100%	Level float on recycle tank stuck during truck offloading	Tanks	Repaired level float. Told operator to strap the tank instead of relying on the level indicator.
KR-8624201	8/30/1986	1B	280	Produced Water-100%	Flange leak in 10" produced water line.	Flanges	NONE.
KR-8624401	9/1/1986	WSAK	105	Crude-20%, Produced Water-80%	Improper wiring caused pump to run backwards, hose pulled loose	Transfer Hoses	The motor was rewired.
KR-8625801	9/15/1986	ROAD	840	Crude-50%, Produced Water-50%	Open valve on vac truck possible cause	Fittings/Seals/ Connections	General info. memo assigned to Kuparuk supervisors.
KR-8629501	10/22/1986	2Z	168	Crude-95%, Produced Water-5%	Valve opened to break vapor locked pump causing overfill of tank #1	Fittings/Seals/ Connections	Engineering to look into installing a check valve in production line and repiping vents from tanks.

TABLE C-1 (CONTINUED): KUPARUK SPILL HISTORY

Spill #	Date	Location	Volume (Gal)	Product	Cause Explanation	Source	Corrective Action
KR-8629502	10/22/1986	ROAD	84	Diesel-100%	Ears on camlock cap broke causing valve to leak	Fittings/Seals/ Connections	Ensure that drivers double check entire truck for leaks before leaving location.
KR-8629901	10/26/1986	2X	60	Produced Water-100%	Bottom plate on 2z-8 pit valve was leaking produced water	Fittings/Seals/ Connections	NONE.
KR-8631103	11/7/1986	CPF1	5040	Crude-1%, Seawater-99%	Sea water storage tank overflowed level transmitter froze	Tanks	Level transmitter was insulated
KR-8631901	11/15/1986	2G	840	Produced Water-40%	Rupture disc on line heater vessel failed	Fittings/Seals/ Connections	Ruptured disc has been blinded. Pressure relief system is being reviewed and checked out.
KR-8636201	12/28/1986	FUEL	84	Diesel-100%	Tank overflow (cpf1 fueling dock)	Tanks	Color code intake fittings.
KR-8700602	1/6/1987	CPF3	84	Motor Oil-50%, Glycol-50%	Overflow of msd sumps	Sumps	Level switches to start sump pumps are being calibrated.
KR-8703301	2/2/1987	2Z	210	Crude-40%, Produced Water-40%, Methanol-20%	Ice layer gave false indication that block valve was closed	Pipe/Flowlines/ Hardline	Housing over these lines will be heated to prevent ice formation.
KR-8706501	3/6/1987	2Z	210	Crude-50%, Diesel-50%	Hose blew off connection.	Transfer Hoses	Check condition of hoses. If driver leaves, loading operations will be shut down until he returns.
KR-8706901	3/10/1987	1A	60	Hydraulic Fluid-100%	Compressor locked up and busted the container case.	Compressor Vents/ Module Vents	Fix air compressor.
KR-8713001	5/10/1987	OWIF	210	Produced Water-40%, Glycol-60%	Overflow of owif captive glycol surge drum.	Tanks	Survey of remainder of module soffit penetrations for good seal.
KR-8718801	7/7/1987	1H	210	Produced Water-40%, Glycol-60%	Leak developed on bundle flange.	Flanges	Shut down line heater and drained remaining fluid to vac truck. Re-torque flange or replace gasket.
KR-8720301	7/22/1987	FUEL	126	Diesel-100%	Employee failed to open all valves on truck while loading	Heavy Equip/Mobile Equip/Vehicles	Check valves more carefully before operating.
KR-8721001	7/29/1987	2H	840	Diesel-100%	Dunnage collapsed,tank shifted and spilled. Tank on low-boy trailer.	Tanks	Review proper methods of supporting tanks.
KR-8721602	8/4/1987	FUEL	84	Diesel-100%	Overfilled rear compartment	Heavy Equip/Mobile Equip/Vehicles	Found true capacity of tank compartments.
KR-8722501	8/13/1987	1B	210	Crude-5%, Freshwater-95%	Flowline developed a leak due to corrosion over a period of time	Pipe/Flowlines/ Hardline	All elbows are being tested
KR-8725702	9/14/1987	3H	630	Crude-50%, Diesel-50%	3" valve faulty cap not secured and vibrated loose during transport	Fittings/Seals/ Connections	Change out valve.
KR-8726201	9/19/1987	ROAD	84	Crude-100%	Slow leak at 24" valve in line 24".	Fittings/Seals/ Connections	Continued observation of cross-country flow lines.

TABLE C-1 (CONTINUED): KUPARUK SPILL HISTORY

Spill #	Date	Location	Volume (Gal)	Product	Cause Explanation	Source	Corrective Action
KR-8728301	10/10/1987	CPF1	84	Crude-100%	Bleed valve off flare header was not fully closed	Fittings/Seals/ Connections	Fully closed bleed valve, inspected valve and repaired as necessary.
KR-8731201	11/8/1987	ROAD	500	Diesel-100%	Broken drive line hit fuel line under truck.	Heavy Equip/Mobile Equip/Vehicles	None
KR-8736401	12/30/1987	KCS	399	Gasoline-100%	Hose came off at pump from tank	Transfer Hoses	Fix hose.
KR-8804301	2/12/1988	1E	1050	Crude-100%	Erosion of 1st piping elbows downstream of wing valve on prod line rise	Pipe/Flowlines/ Hardline	Engineering will investigate using tees instead of elbows in piping in high GOR wells.
KR-8804401	2/13/1988	1G	210	Hydrocarbons, chlorides-1%, Freshwater-99%	Unknown.	Not Specified	N/A.
KR-8804501	2/14/1988	OWIF	84	Crude-10%, Produced Water-90%	Vac truck operator disconnected hose from owif riser	Transfer Hoses	Operator given a warning.
KR-8813701	5/16/1988	OWIF	84	Crude-49%, Produced Water-51%	Backflow thru offloading line into drip tank resulted in overflow	Heavy Equip/Mobile Equip/Vehicles	Individuals have been counseled on off loading procedures.
KR-8813801	5/17/1988	2G	60	Diesel-100%	Snow/ice lodged against plumbing pushing suction manifold away from	Fittings/Seals/ Connections	Replace seal with metal/laminate seal. Isolate tank fluid by closing all manifold valves when not in use.
KR-8816501	6/13/1988	3H	65	Diesel-95%, Other-5%	Gasket on hot oil truck's centrifugal pump failed.	Pumps	None.
KR-8817601	6/19/1988	CPF1	84	Crude-10%, Freshwater-90%	Driver disconnected hose from vac truck.	Transfer Hoses	Driver reinstructed.
KR-8817801	6/26/1988	ROAD	84	Diesel-100%	Plug vibrated out of false compartment on rear of tank.	Heavy Equip/Mobile Equip/Vehicles	Check plugs and connections on tankers more often.
KR-8818002	6/28/1988	2Z	70	Hydraulic Fluid-100%	Broken hydraulic line on trenching machine.	Heavy Equip/Mobile Equip/Vehicles	Change hydraulic oil filter.
KR-8820001	7/18/1988	2D	100	Diesel-100%	During loading a camlock connection loosened.	Transfer Hoses	Replace 'ears' on cam-lock.
KR-8820202	7/20/1988	EPIT	300	Diesel-100%	Cracked pipe nipple at fuel tank.	Pipe/Flowlines/ Hardline	--
KR-8823501	8/23/1988	3O	210	Gel Diesel-100%	Tree saver relief valve opened when working pressure on frac job.	Fittings/Seals/ Connections	Chain or affix relief hose better in slop tank.
KR-8825502	9/11/1988	FUEL	100	Diesel-100%	Overloaded truck	Heavy Equip/Mobile Equip/Vehicles	Drivers reinstructed, truck checked over.
KR-8825901	9/15/1988	1R	294	Diesel-100%	Check valve failed in down hole pump at 1r-8	Fittings/Seals/ Connections	Replace bad valve

TABLE C-1 (CONTINUED): KUPARUK SPILL HISTORY

Spill #	Date	Location	Volume (Gal)	Product	Cause Explanation	Source	Corrective Action
KR-8827401	9/30/1988	3O	420	Diesel-100%	Small hole in dike -leakage from data frac operations within dike.	Tanks	Pit liners and hose connections will be checked when breaking lines and transferring fluids.
KR-8827501	10/1/1988	3N	336	Diesel-50%, Seawater-50%	Packoff on 1-1/2 coiled tubing failed.	Coiled Tubing Unit/ Wireline Equip	Wells with high sitp will be evaluated more closely for ctu cleanouts.
KR-8828901	10/15/1988	1F	252	Diesel-34%, Viscsified Brine-33%, Seawater-33%	Runover from well cellar during workover operations	Coiled Tubing Unit/ Wireline Equip	Keep cellar vacuumed down
KR-8829101	10/17/1988	KCS	91	Gasoline-100%	Overflowed tank on fuel delivery truck.	Heavy Equip/Mobile Equip/Vehicles	Driver was told to watch tanks as they are being filled.
KR-8829901	10/25/1988	2Z	55	Crude-25%, Diesel-75%	While removing snow hit barrel and poked a hole in it.	Drums/Containers/ Dumpsters	Notified CPF's to keep areas clean or clearly marked.
KR-8833301	11/28/1988	2A	85	Hydraulic Fluid-100%	Trenching machine blew an oil filter housing	Heavy Equip/Mobile Equip/Vehicles	A hydraulic oil temperature and pressure gauge are being installed along with an emergency shutdown switch.
KR-8834001	12/5/1988	1G	420	Diesel-100%	Cam lock fitting broke loose from hose circulating diesel.	Transfer Hoses	Check banding on a regular basis and will watch over fittings more closely while pumping fluids.
KR-8835201	12/17/1988	1Y	126	Refined Product-100%	Nipple on outlet washed out while injecting fluids into annulus	Coiled Tubing Unit/Wireline Equip	Check well head screwed connections more frequently.
KR-8836102	12/26/1988	1Y	168	Diesel-100%	Priming plug on pump blew out. Pump in lined area but wind dispersed.	Pumps	None.
KR-8836101	12/26/1988	3O	336	Crude-50%, Diesel-50%	Gas surge in flowback tank during coiled tubing work at well 2	Tanks	Keep flowback tank at a lower volume.
KR-8836201	12/27/1988	1A	2100	Crude-5%, Produced Water-95%	Bleeder plug failed. Produced water leaked out of module onto pad.	Fittings/Seals/ Connections	Investigated swagelock bleeder plug, found to be a fuseable cap which melts at 160 deg. Educated operators on difference.
KR-8900304	1/3/1989	1H	168	Crude-98%, Freshwater-2%	While trenching, liner encountered abandoned crude oil line	Pipe/Flowlines/ Hardline	Be made aware of abandoned oil lines.
KR-8903803	2/7/1989	WSAK	200	Diesel-100%	Fuel tank drain valve failed due to cat train cat-trailer collision.	Heavy Equip/Mobile Equip/Vehicles	Operators informed to secure trailers together more tightly on downhill grades to prevent towed trailers from colliding with towing
KR-8903802	2/7/1989	OWIF	168	Crude-1%, Freshwater-99%	Gasket failed on vac truck while unloading hot oily water.	Heavy Equip/Mobile Equip/Vehicles	Gasket is being replaced and driver to make frequent inspections.
KR-8904201	2/11/1989	CPF2	420	Crude-5%, Produced Water-95%	Produced water header gasket failed fluid leaking out of door.	Fittings/Seals/ Connections	None.

TABLE C-1 (CONTINUED): KUPARUK SPILL HISTORY

Spill #	Date	Location	Volume (Gal)	Product	Cause Explanation	Source	Corrective Action
KR-8911201	4/22/1989	1Y	168	Crude-50%, Diesel-50%	Trash pump failed during pumping operation.	Pumps	Pump will be placed in liner in future operations.
KR-8912101	5/1/1989	1Y	84	Diesel-100%	Well head foundation heated. Diesel surfaced during activity.	Coiled Tubing Unit/ Wireline Equip	Drilling has been contacted to determine cause and f/u action.
KR-8912301	5/3/1989	FUEL	60	Diesel-100%	Source tank on well service truck was overfilled.	Heavy Equip/Mobile Equip/Vehicles	None.
KR-8912501	5/5/1989	CPF1	210	Crude-1%, Produced Water-99%	A drip tank, punctured while being relocated, leaked fluid when used.	Tanks	Investigating option of providing a dedicated drip tank for each vessel which may reduce the number of times tanks require handling.
KR-8914001	5/20/1989	CPF2	84	Crude-2%, Produced Water-98%	Gasket failed on vac truck tail gate spilling produced water to pad.	Heavy Equip/Mobile Equip/Vehicles	Drivers were instructed to clean and inspect tailgate gasket after every load.
KR-8915303	6/2/1989	CPF2	84	Crude-100%	Produced water tank level indicator failed. Overflowed to flare pit.	Tanks	Produced water crude skimming operations suspended until level indicator repaired.
KR-8918601	7/5/1989	1R	420	Diesel-100%	Weld failed on coiled tubing unit	Heavy Equip/Mobile Equip/Vehicles	None.
KR-8921901	8/7/1989	OWIF	840	Crude-1%, Freshwater-99%	Weld near corrosion coupon broke on disposal well line	Pipe/Flowlines/ Hardline	Replace area of pipe near coupon. Increase corrosion inspection frequency on this line.
KR-8923701	8/25/1989	2U	25200	Crude-85%, Produced Water-15%	Valve component failed and allowed crude to leak from valve assembly.	Fittings/Seals/ Connections	Replaced valve and addressing cause of valve component failure. Continue pipeline surveillance. Keep boom in place into next summer.
KR-8931201	11/8/1989	2G	7560	Crude-100%	Break in temporary line on well #4.	Pipe/Flowlines/ Hardline	Use manifold choke during flowback.
KR-8933001	11/26/1989	2D	63	Crude-5%, Produced Water-35%, Methanol-60%	While thawing frozen flowline flange leaked.	Flanges	Review standard procedure.
KR-9000601	1/6/1990	1Y	336	Crude-1%, Produced Water-99%	Flange gasket on drain line failed due to ice plug block in line.	Flanges	Change sop for purging drain line to include air purge.
KR-9001901	1/19/1990	1L	100	Hydraulic Fluid-100%	Hydraulic filter failed causing fluid loss.	Heavy Equip/Mobile Equip/Vehicles	Rechecked entire hydraulic system.
KR-9001902	1/19/1990	OW1F	630	Diesel-1%, Hydraulic Fluid-1%, Freshwater-98%	Bottom dump safety plug blew out. Mechanical failure.	Fittings/Seals/ Connections	Equipment being repaired.

TABLE C-1 (CONTINUED): KUPARUK SPILL HISTORY

Spill #	Date	Location	Volume (Gal)	Product	Cause Explanation	Source	Corrective Action
KR-9002301	1/23/1990	1L	70	Hydraulic Fluid-100%	Hydraulic filter damaged by rock, failed and leaked fluid to pad.	Heavy Equip/Mobile Equip/Vehicles	Operators instructed to periodically monitor for foreign objects that might pose an equipment problem and to check filters and fittings.
KR-9013201	5/12/1990	3F	84	Diesel-100%	Plug failed while pressuring up on test to well #11. Threads fatigued.	Plug	Reinspect all fittings before starting job.
KR-9021102	7/30/1990	CPF1	75	Diesel-100%	Unknown. Operator found diesel in trench while making rounds.	Unknown	Unknown at this time.
KR-9021801	8/6/1990	1R	63	Diesel-100%	Coiled tbg unit pulled out of stripper when pulling out of the hole. Crew thought the tools were larger in diameter than the hole.	Coiled Tubing Unit/ Wireline Equip	CTU crew cautioned to be more careful when pulling up to stripper.
KR-9021901	8/7/1990	2T	168	Produced Water-50%, Other-50%	While gelling tanks prior to frac job, a discharge hose on a frac tank ruptured.	Transfer Hoses	Inspect hoses carefully prior to start of job.
KR-9023101	8/19/1990	1E	420	Produced Water-100%	Low pressure switch failed water filled module and spilled out doors and soffit.	Fittings/Seals/ Connections	--
KR-9023801	8/26/1990	CPF1	840	Produced Water-99%, OFC CL922 Soap-1%	During tank washing the tap used to visually monitor high liquid level within the tank was plugged. This prevented the operator from detecting the liquid level before it carried over through vent to pad.	Tanks	Sample tap used for visual high high level indication was unplugged.
KR-9026801	9/25/1990	2U	210	Crude-1%, Seawater-99%	Seawater during pigging operation was caught by wind and blown over cable trays, pipelines and vsms near drillsite module	Drums/Containers/ Dumpsters	Provide some sort of wind deflection
KR-9027401	10/1/1990	3F	55	Hydraulic Fluid-100%	Hydraulic hose under truck chassis broke.	Transfer Hoses	Hoses were repaired and others inspected for wear.
KR-9034702	12/13/1990	FUEL	580	Diesel-100%	Driver drove away from loading dock without disconnecting fueling hose from vehicle.	Heavy Equip/Mobile Equip/Vehicles	Driver instructed on cause and need to remove hose connection from tank when fueling complete.
KR-9036201	12/28/1990	FUEL	100	Diesel-100%	Operator claimed pump meter didn't register correctly, tanker was overfilled. Cpf-1 facility supervisor confirmed meter failed.	Heavy Equip/Mobile Equip/Vehicles	Driver will check meter and visually monitor fuel level.
KR-9104701	2/16/1991	1A	210	Crude-1%, Produced Water-99%	Bleed valve on flow line pilot froze in open position. Not checked when well put on line	Pipe/Flowlines/ Hardline	--
KR-9105101	2/20/1991	ROAD	154	Diesel-10%, Hydraulic Fluid-90%	Hose parted from king nipple on 45 ton crane. Fluid drained to roadway	Heavy Equip/Mobile Equip/Vehicles	--
KR-9107401	3/15/1991	FUEL	123	Diesel-100%	During loading truck overflowed.	Heavy Equip/Mobile Equip/Vehicles	--

TABLE C-1 (CONTINUED): KUPARUK SPILL HISTORY

Spill #	Date	Location	Volume (Gal)	Product	Cause Explanation	Source	Corrective Action
KR-9110101	4/11/1991	FUEL	55	Diesel-100%	Fuel tank level gauge failed to accurately indicate diesel level in tank.	Tanks	Have man on tank watching fluid level during loading.
KR-9111201	4/22/1991	FUEL	150	Diesel-100%	Valve stuck on tanker.	Heavy Equip/Mobile Equip/Vehicles	--
KR-9112001	4/30/1991	3G	210	Diesel-100%	Coil tubing parted under operating pressure.	Coiled Tubing Unit/Wireline Equip	Dowell will inspect tubing more frequently.
KR-9112901	5/9/1991	1A	63	Crude-100%	Camlock fitting failed on hot oil unit.	Heavy Equip/Mobile Equip/Vehicles	--
KR-9113301	5/13/1991	CPF2	125	Crude-100%	Sometime during the past winter period,suction side of module sump pump plugged. Sump overflow drained to flare pit. Remnants of spill observed as thaw progressed.	Sumps	--
KR-9114701	5/27/1991	KCS	200	Unknown Hydrocarbon-100%	Plug knocked out of tank by unknown party. Tank owner is unknown.	Tanks	Monitor the pad after breakup for additional runoff
KR-9115701	6/6/1991	1B	210	Produced Water-100%	Injection choke washed out and water sprayed out bonnet flange on choke and out well house doors.	Pipe/Flowlines/ Hardline	--
KR-9119205	7/11/1991	3B	2268	Produced Water-50%, Seawater-50%	Leaking drain valve.	Pipe/Flowlines/ Hardline	Replaced drain valve.
KR-9119703	7/16/1991	2M	105	Motor Oil-100%	Engine oil leak out the bottom of a blown engine.	Heavy Equip/Mobile Equip/Vehicles	Better maintenance of vehicles.
KR-9119903	7/18/1991	1Q	168	Diesel-100%	Hose ruptured on unit during fluid transfer.	Transfer Hoses	Inspect all hoses each month and pressure test all hoses quarterly.
KR-9123701	8/25/1991	CPF2	168	Crude-60%, Pump Seal Oil-40%	--	Unknown	Monitor flare pit after cleanup to assure no residual drainage from overflow line.
KR-9132902	11/25/1991	2M	86	Diesel-50%, Drilling Mud-50%	Hose t injection well disconnected with valve open.	Transfer Hoses	--
KR-9134103	12/7/1991	1E	4200	Crude-1%, Produced Water-99%	Barton recorder diaphragm failure due to ice build-up in the instrument. Discharge occurred thru tubing vent line.	Compressor Vents/ Module Vents	Local recording devices have been removed from service, sensing lines have been capped. Instrument will be moved to a heated enclosure.
KR-9204901	2/18/1992	1R	210	Crude-10%, Produced Water-90%	Header fluid backflowed through leaky check valve to 1R-7 riser, where a 1/2" valve was open in wellhouse.	Pipe/Flowlines/ Hardline	Operators were instructed that spill could have been avoided by working with one line at a time, at both ends of flowlines.
KR-9214401	5/23/1992	1F	84	Diesel-40%, Freshwater-60%	Mechanical seal failure on Well Head.	Fittings/Seals/ Connections	Contacted FMC wellhead representative for advice.

TABLE C-1 (CONTINUED): KUPARUK SPILL HISTORY

Spill #	Date	Location	Volume (Gal)	Product	Cause Explanation	Source	Corrective Action
KR-9215902	6/7/1992	2H	250	Diesel-100%	Union on top half of bridel connection level transmitter to tank loosened, causing slow leak.	Fittings/Seals/ Connections	An inspection of all bridal unions on all diesel storage tanks for CPF2 will take place.
KR-9217401	6/22/1992	CPF1	840	Bioversal-10%, Freshwater-90%	Damaged liner in containment area leaked wash water to gravel pad.	Sumps	Liner repaired.
KR-9219701	7/15/1992	2Z	120	Diesel-75%, Produced Water-25%	While unbolting and removing strainer, liquid started flowing from the strainer. The bleed valve was opened first to bleed off liquid, but became clogged.	Fittings/Seals/ Connections	A larger bleed valve was installed. Operator instructed to insure all pressure is bled off before opening strainer. These actions took place during facility operations. Operations at 2Z recycle facility have been moved to CPF1 OWIF.
KR-9225501	9/11/1992	3B	84	Diesel-100%	Welded joint on a coil tubing unit failed while pumping diesel during a cleanout operation.	Fittings/Seals/ Connections	Implement non-destructive hardness testing for welded and heat affected areas.
KR-9226101	9/17/1992	2M	336	Diesel-100%	While doing Hydro test on gas lift line, fitting at manifold building was not tightened.	Fittings/Seals/ Connections	Under investigation.
KR-9226601	9/22/1992	1R	420	Crude-2%, Diesel-98%	While rigging up a Coiled Tubing Unit to a Tiger tank fitting, improper valve placement behind the fitting caused the quick cam lock to release.	Fittings/Seals/ Connections	Correct the manifolding design to a more appropriate configuration.
KR-9227201	9/28/1992	3N	546	Diesel-60%, Methanol-40%	Valve failure on down hole pump.	Fittings/Seals/ Connections	Pump will be taken to the shop and repaired.
KR-9230701	11/2/1992	1R	420	Crude-10%, Diesel-90%	Manway access cover gasket failed allowing fluids to leak into diked area. These fluids then exited the lined, diked area through a tear in the liner out onto the pad.	Fittings/Seals/ Connections	Inspect manway gaskets, tighten hatch covers after they have been warmed to allow the gaskets to be pliable, and replace liner.
KR-9234602	12/11/1992	1G	126	Diesel-100%	On a downhole pump unit, frac sands held the PSV open enough to cause fluids to flow into the 70 bbl tank causing an overflow.	Pumps	--
KR-9305201	2/21/1993	1R	210	Diesel-100%	Pump valving jammed open by gravel in fluids allowing well to backflow diesel to vac truck.	Pumps	Employees instructed on procedures to follow should pump become plugged.
KR-9305501	2/24/1993	3B	82	Crude-10%, Diesel-90%	Steam cleaning water left in fill riser froze causing the line to split. During the flowback the fluids siphoned to the split on the outside of the tank and slowly seeped out into secondary containment.	Tanks	This tank had just been returned to service following cleaning and internal modification. Stagnate lines should be vacuumed or filled with nonfreezing material.
KR-9312501	5/5/1993	CPF1	84	Crude-2%, Produced Water-98%	Operator left valve open on tanks while the test sample was being taken.	Tanks	Operator will be disciplined for violation of work procedures and will receive further instruction in proper work rules and regulations.

TABLE C-1 (CONTINUED): KUPARUK SPILL HISTORY

Spill #	Date	Location	Volume (Gal)	Product	Cause Explanation	Source	Corrective Action
KR-9322902	8/17/1993	CPF1	31500	Crude-90%, Produced Water-10%	Holes caused by external corrosion on the tank floor allowed fluid to escape.	Tanks	–
KR-9324501	9/2/1993	2C	4620	Crude-54%, Produced Water-46%	Corrosion leak in 18" PO line.	Pipe/Flowlines/ Hardline	Under investigation.
KR-9326301	9/20/1993	CPF1	336	Crude-10%, Diesel-90%	Bleed tank overfilled during freeze protection preparations of Divert tank to/from line.	Tanks	Discussed with employee the importance of rechecking all aspects on a system when a change has been made to any part of that system.
KR-9327401	10/1/1993	1Y	84	Diesel-100%	Flange not tightened at module leaked during pre-frac work on well.	Fittings/Seals/ Connections	All lines being hooked up will be leak tested right after hook-up. When the WSG is going to pump on the annulus of a new well, the L/G riser will be removed first.
KR-9329301	10/20/1993	1Q	84	Crude-35%, Produced Water-65%	1Q-5 Bleeder on Riger leaking	Fittings/Seals/ Connections	Increase awareness of valve positions.
KR-9403601	2/5/1994	1F	2100	Produced Water-100%	Mechanical failure of the 1f-15 water injection well line near the pit valve. Produced water sprayed a fine mist out a slot approx 1/8" wide by 4" long.	Pipe/Flowlines/ Hardline	Line will be inspected/repaired prior to returning the well to service. Lines similarly constructed will be non-destructive tested this summer.
KR-9412701	5/7/1994	2E	212.5	Diesel Gel-100%	Driver was transferring diesel gel from tank to truck. Got truck too full. Had hose tied off over top of tank. When he blew back into tank the hose came untied and fell out of tank.	Transfer Hoses	Make sure driver and truck have right connections to hook up to load valve on tank so he does not have to put hose over top.
KR-9419101	7/10/1994	CPF1	80	Crude-100%	On routine check of Flare system oil was observed inside the East Flare Pit. The only source would be from the CPF1 Facility Module Sump Drain Overflow.	Sumps	Reminded unit operators to frequently check MSD levels.
KR-9430401	10/31/1994	CPF1	23100	Crude-30%, Produced Water-70%	Crack in flowline.	Pipe/Flowlines/ Hardline	Field wide corrosion inh bition program spending has increased from $9.5 million in 94 to $15 million in 95. Corrosion surveillance inspection has been increased in suscept ble areas.
KR-9430601	11/2/1994	CPF1	2100	Crude-1%, Potable water-99%	Flange leak due to ice plug in line.	Flanges	Thaw out frozen section and insulate properly.

TABLE C-1 (CONTINUED): KUPARUK SPILL HISTORY

Spill #	Date	Location	Volume (Gal)	Product	Cause Explanation	Source	Corrective Action
KR-9500601	1/6/1995	1B	420	Crude-50%, Diesel-50%	Fill line on flowback tank broke at 90 degree elbow. Line was not pressurized. Line was most likely broken prior to spotting tank at location or during set up.	Pipe/Flowlines/ Hardline	Discuss tank inspection at morning meeting. Inspect other tanks used for flowback. Downcomer on fill line on flowback tanks used at Kuparuk are being removed when the tank has an internal inspection.
KR-9500701	1/7/1995	3M	252	Crude-85%, Produced Water-15%	Bushing on external swing arm of a 12" check valve on main production line from drill site 3M to 3I failed allowing crude oil, gas and produced water to leak out of the line and onto the snow which covers the 3M drill site and tundra.	Fittings/Seals/ Connections	A cap for the swing arm was made and installed in place of the leaking bushing. Continue tundra valve PMs, monitoring pipelines and valves away from main drill sites.
KR-9501602	1/16/1995	CPF2	200	Crude-100%	1/16/95-Communication between 9-5/8" surface casing and 16" conductor pipe, which is most likely the result of drill pipe wear on the 9-5/8" casing. Converting the well from a seawater (60 degree F) to produced water (140 degree F) injector, increased the temperature and expanded the thaw bulb around the well bore, resulting in fluid and gas seepage from the 16" casing. 6/8/05-Additional contamination was encountered while repairing a surface casing leak. ADEC, ADNR, NSB and AOGCC were notified. Further investigation revealed that the surface casing had pressure damage, extending down at least 30' from the surface.	Pipe/Flowlines/ Hardline	Repaired conductor casing with welded patch, installed 3' circulating nipple below Tanko-Head on the conductor, and received approval from AOGCC to operate well in water injection service.
KR-9503801	2/8/1995	1R	797.5	Crude-43%, Produced Water-57%	1R-20 eroded out an e bow in the manifold building (1R-20).	Pipe/Flowlines/ Hardline	Pipe repaired, well put on list of wells monitored by corrosion.
KR-9506101	3/2/1995	3M	630	Diesel-30%, Other-70%	While in the process of circulating 11.5 brine out of the 7" casing to a 400 bbl. Upright tank, the tank overflowed. The well had started flowing up the backside, increasing the rate of return to the tank.	Tanks	Establish rate of return to tank by getting tank straps very often at the beginning of job. Discuss incident at safety meetings.
KR-9506501	3/6/1995	1R	189	Crude-45%, Produced Water-55%	Production choke on 1R-20 developed a hole. The hole was caused by erosion.	Fittings/Seals/ Connections	Choke repaired. Evaluating other options on how to choke well.
KR-9515401	6/3/1995	1A	110	Hydraulic Fluid-100%	Hose burst after pulling drill pipe out of hole, causing hydraulic fluid to spill in cellar.	Transfer Hoses	Hose to be checked for wear, replaced if necessary.

TABLE C-1 (CONTINUED): KUPARUK SPILL HISTORY

Spill #	Date	Location	Volume (Gal)	Product	Cause Explanation	Source	Corrective Action
KR-9521801	8/6/1995	2C	1260	Produced Water-100%	The injection flowline for 2C4 ruptured and spilled produced water onto gravel pad under the module. 2C is a produced water injection well. Cause of failure is suspected to be corrosion.	Pipe/Flowlines/ Hardline	Insulation is being removed from adjacent well lines to inspect for corrosion. Corrosion Engineering is performing breakdown analysis to verify cause of failure and recommendation to go forward.
KR-9525401	9/11/1995	1Q	2310	Crude-10%, Solids-25%, Freshwater-65%	After pumping down the cutting tank, pump was shut off. Discharge valve was left open allowing 400 barrel holding tank to siphon back through line into the cutting tank, over running tank.	Sumps	Discharge line will be modified to prevent this. High level tank alarm will be installed on cuttings tank. All crew members will be informed of the events that caused this incident to occur and how to prevent it.
KR-9529601	10/23/1995	2E	269	Produced Water-100%	Leak in valve caused produced water to fill manifold bldg up to door threshold and then leak onto pad and reserve pit.	Fittings/Seals/ Connections	The valve on 2E-14 was repaired with a new gasket.
KR-9535601	12/22/1995	1H	539	Produced Water-100%	Pig receiver produced water outlet line, Mueller quick turn blind gasket failed. Crude component of fluids spilled was 900 ppm.	Fittings/Seals/ Connections	Alternative flange gaskets being reviewed for possible substitute. Reviewing installation procedures and will update if necessary.
KR-9536501	12/31/1995	CPF1	440	Produced Water-100%	Sand jet tank filled with produced water to thaw frozen sand. Fluid level was 6-8 inches from top of tank. Vac truck driver walked around dike and noticed water soaked snow. Appeared to be a hole in the tank.	Tanks	Hole will be located and repaired as soon as possible. Dike liner will be replaced and tank cleaned when weather warms up.
KR-9600701	1/7/1996	2D	8820	Produced Water-100%	Ice plug melted in the pig launcher drain valve, which was slightly cracked open and not plugged.	Pipe/Flowlines/ Hardline	Maintain module temperature above freezing. Exercise standard operating practice of plugging drain valves, bleed valves, or other terminal valves.
KR-9605601	2/25/1996	1F	240	Produced Water-90%, Methanol-10%	Over-topped tank during blow-down of test separator.	Tanks	Re-design work in process.
KR-9607001	3/10/1996	2B	294	Crude-10%, Diesel-30%, Seawater-30%, Methanol-30%	DSO was flushing test separator into open top tank. Drain cap was not installed on weir end of tank, causing the over-topped tank to spill through open drain.	Tanks	Remove drifted snow from around tanks and inspect tank set-ups to ensure all drains are plugged and readily visible while performing the job.
KR-9614701	5/26/1996	OWIF	294	Crude-80%, Produced Water-20%	During the final stages of offloading a vac truck, a mixture of produced water and crude flowed over the shale shaker into the solids bin, which then overflowed onto the OWIF module floor.	Heavy Equip/Mobile Equip/Vehicles	Check LSHH-10002E for proper operation; repair as necessary. Check local PC for proper operation, repair as necessary.
KR-9618801	7/6/1996	1Y	630	Crude-20%, Produced Water-80%	The cause of the stainless steel tubing failure was erosion.	Pipe/Flowlines/ Hardline	Stainless steel tubing being replaced with re-engineered design to accommodate the high solids flow. In addition, procedure to reduce flow rates has also been identified.

TABLE C-1 (CONTINUED): KUPARUK SPILL HISTORY

Spill #	Date	Location	Volume (Gal)	Product	Cause Explanation	Source	Corrective Action
KR-9622801	8/15/1996	3J	126	Crude-15%, Produced Water-85%	3J pad pig pit liner failed, allowing produced water to contaminate gravel under liner located inside the reserve pit.	Sumps	The failed liner was eight years old. Since that time, pit liner installation technology has vastly improved. The pit is presently being reworked using latest techniques and liner materials.
KR-9622901	8/16/1996	CPF1	84	Crude-99%, Produced Water-1%	Drain valve and sight glass plugged off.	Tanks	Cleaned and serviced drain valve. Work order initiated to repair sight glass and install secondary containment under pig launcher.
KR-9623401	8/21/1996	CPF3	120	Crude-10%, Freshwater-90%	Removal of blind released small accumulation of oily water condensate after a three week period of blinding. Wind caught liquid and blew it outside of secondary containment.	Sumps	Install temporary containment system at the point of flanges.
KR-973601	2/5/1997	2F	60.1	Hydraulic Fluid-100%	Ruptured hydraulic hose.	Transfer Hoses	Permanent secondary containment was previously mounted on crane as preventative measure. Containment caught all but 1 pint of oil.
KR-973801	2/7/1997	2F	84	Diesel-100%	Operator left transport valve open to the on-board tank in the pump, causing tank to overflow.	Heavy Equip/Mobile Equip/Vehicles	Close valves to on-board tank when pumping from transport.
KR-974402	2/13/1997	1C	90	Hydraulic Fluid-100%	Frayed hydraulic hose on 45-ton crane.	Heavy Equip/Mobile Equip/Vehicles	Check and change hoses more frequently.
KR-977501	3/16/1997	2F	84	Produced Water-50%, Cement-50%	Operator opened wrong valve on the truck, which had an open-ended hose on it that the crew was rolling up.	Heavy Equip/Mobile Equip/Vehicles	Do not disconnect hose until wash-up is finished.
KR-9712001	4/30/1997	CPF2	1732	Crude-1%, Produced Water-99%	The freeze protect heat trace failed, resulting in the line being damaged by the frozen liquid.	Pipe/Flowlines/ Hardline	The flare MSD line has been removed from service and blinded.
KR-9712301	5/3/1997	CPF1	98	Crude-100%	Source of spill was the flare knockout. CPF-3 wet oil line PSV's lifted at set point and relieved to the flare knockout which carried over to the flare line and liquids were carried over the flare pits. 48 gallons was discharged into the west pit and 50 gallons into the east pit.	Tanks	Obstruction in bridle was cleared. FWR to modify bridle was included in June shutdown work.
KR-9717301	6/22/1997	2B	462	Diesel-100%	After slickline operations, a hard line was left connected to the wellbore. Twenty-two barrels of diesel were in the wel bore, and eleven barrels leaked through the hardline.	Pipe/Flowlines/ Hardline	If tanks are rigged to well via hardline, when removed the hardline will also be disconnected. A cap will be installed on the temporary wing in place of the hardline.

TABLE C-1 (CONTINUED): KUPARUK SPILL HISTORY

Spill #	Date	Location	Volume (Gal)	Product	Cause Explanation	Source	Corrective Action
KR-9719601	7/15/1997	3B	2000	Crude-35%, Produced Water-65%	External corrosion under insulation at weldpack.	Pipe/Flowlines/ Hardline	Prior to restart of the line, the balance of the weld pack insulated areas were inspected. Wet ones or suspect ones had the insulation stripped and the pipe visually and electronically inspected.
KR-9724901	9/12/1997	CPF2	840	Crude-100%	During restart of the primary separator, excess oil from the full separator was routed to flare header and subsequently caused a plant shutdown. Due to elevated pressures, oil was forced out the flare system into the flare pit.	Compressor Vents/ Module Vents	Develop and update startup procedures and discuss with appropriate personnel.
KR-9731201	11/8/1997	1E	336	Crude-5%, Drill mud-95%	Flow riser seal failure.	Fittings/Seals/ Connections	Install T. V. monitor in cellar for visual monitoring.
KR-9732001	11/16/1997	CPF1	3030	Crude-1%, Produced Water-99%	XXS elbow upstream of different thickness than piping and rest of e bows, causing increased velocity through the e bow and a washout of the downstream piping.	Pipe/Flowlines/ Hardline	New section of pipe installed with new heat trace/insulation. The line's elbows will be inspected to monitor for further problems. Limit to reduced pumping rates as frequently as possible.
KR-9735501	12/21/1997	CPF1	125	Crude-50%, Produced Water-50%	Oil/produced water valve on the coalescer was left open during sample checking.	Fittings/Seals/ Connections	Impress upon operator the importance of continuously monitoring any type of bleeding activity.
KR-981001	1/10/1998	1A	63000	Produced Water-100%	Pipeline failure.	Pipe/Flowlines/ Hardline	Preventive action to be determined based on results of failure analysis of pipe.
KR-981601	1/16/1998	2M	84	Crude-5%, Diesel-5%, Produced Water-90%	2M-10 CTU open top flowback tank loading valve was partially open while tank was being filled with clean-out fluids.	Tanks	Valve was repositioned to stop leak.
KR-982601	1/26/1998	OWIF	152	Crude-100%	Decanted liquid sump overfilled to secondary containment due to frozen instrumentation caused by a plugged Y strainer.	Sumps	Y-strainer removed from heating glycol line.
KR-986201	3/3/1998	3A	204.5	Crude-5%, Produced Water-95%	Flowline weld failure inside manifold building.	Pipe/Flowlines/ Hardline	Continued x-ray and UT surveillance on manifold building piping, especially on high flow rate wells.
KR-988001	3/21/1998	1Y	1260	Produced Water-33%, Freshwater-27%, Methanol-40%	Pipeline failure.	Pipe/Flowlines/ Hardline	Insure sufficient displacement of flow line with anti-freezing fluids.
KR-9810301	4/13/1998	1Y	2100	Produced Water-100%	Rubber O-ring failure on PW pig receiver.	Fittings/Seals/ Connections	Performed an audit of the incident and will inspect condition of o-rings before starting the pigging job. O-rings will be replaced as needed.

TABLE C-1 (CONTINUED): KUPARUK SPILL HISTORY

Spill #	Date	Location	Volume (Gal)	Product	Cause Explanation	Source	Corrective Action
KR-9813701	5/17/1998	CPF1	126	Crude-100%	MSD overflowed to the flare during a draining operation.	Sumps	Spill will be reviewed in the facility tailgate meeting; reinforce necessity to closely monitor sump levels when using for operational purposes.
KR-9823601	8/24/1998	1L	420	Produced Water-100%	Flowline rupture due to internal corrosion.	Pipe/Flowlines/ Hardline	The SSV and IPV closed on failing pressure isolating the flowline from the wellhead and the manifold.
KR-9827602	10/3/1998	CPF3	200	Crude-65%, Produced Water-35%	Wet oil booster pump seal leak.	Pumps	Replaced seal.
KR-9827901	10/6/1998	1L	10500	Crude-1%, Produced Water-99%	Produced water injection flow line failure; internal corrosion.	Pipe/Flowlines/ Hardline	Increase corrosion inspection program.
KR-9829601	10/23/1998	CPF1	150	Diesel-100%	Fuel tanker overfilled due to use of wrong computer.	Heavy Equip/Mobile Equip/Vehicles	Ensure correct use of computer.
KR-9835801	12/24/1998	CPF1	200	Motor Oil-100%	Overfilled STV overhead lube oil reservoir while doing other job duties.	Tanks	Review procedure for lube oil transfer as well as review installation of a timer to automatically shutdown the transfer operation.
KR-9919101	7/10/1999	3F	69	Electrical transformer oil-100%	The insulator connection going into the transformer was broken and cracked allowing the internal oil to leak out.	Fittings/Seals/ Connections	Shut down transformer and damage assessment in progress by Electricians. Notice sent out to all area Supervisors to inspect for spills under all other transformers located throughout the field.
KR-9920401	7/23/1999	1A	6300	Crude-1%, Produced Water-99%	The damage to the produced water line was caused by external corrosion at a weld pack in a saddle.	Pipe/Flowlines/ Hardline	To be determined.
KR-9922701	8/15/1999	1L	1350	Crude-1%, Produced Water-99%	Gasket failure on produced water pig receiver door failed spilling produced water into the manifold building and eventually flowed out onto the pad.	Fittings/Seals/ Connections	Isolated receiver, replaced gasket.
KR-9924902	9/6/1999	3F	65	Hydraulic Fluid-100%	Hydraulic oil filter gasket blew out.	Heavy Equip/Mobile Equip/Vehicles	Remove filters from system or replace with canister style housings.
KR-9931401	11/10/1999	CPF3	150	Crude-100%	Packing leaked on the slop oil tank.	Pumps	Pump was blocked in a work order has been written.
KR-9931502	11/11/1999	CPF1	100	Crude-1%, Produced Water-99%	The suction boot failed on the booster pump.	Pumps	Replace boot with a new one.
KR-9932601	11/22/1999	2X	214	Diesel-100%	A production flow line that was shut in and freeze protected with diesel ruptured. The spill cause is under investigation.	Pipe/Flowlines/ Hardline	When the incident investigation has been completed the findings will be followed up on.

TABLE C-1 (CONTINUED): KUPARUK SPILL HISTORY

Spill #	Date	Location	Volume (Gal)	Product	Cause Explanation	Source	Corrective Action
KR-003801	2/7/2000	CPF2	8400	Produced Water-100%	Sump overflowed into tertiary containment. The level controller for the sump is suspected to not be working properly.	Sumps	FWR written to check the level control operations and verify the auto start operation of the sump pumps.
KR-004501	2/14/2000	1Y	225	Produced Water-100%	A leaking grease fitting on the pig launcher block valve.	Fittings/Seals/ Connections	Valve crew installed a piggyback grease fitting and pumped sealant into valve. A "shutdown" FWR # L906718 has been generated to replace the original grease fitting.
KR-0012201	5/1/2000	2V	201	Diesel-100%	Tree cap o-ring failed leaking diesel down the tree. Swab valve was closed but leaking badly.	Fittings/Seals/ Connections	Serviced swab valve and replaced 0-ring.
KR-0012702	5/6/2000	2M	200	Crude-78%, Produced Water-22%	The spill occurred because a crack had developed on top of the valve/S-riser flange. The crack was determined to have been caused by gravel subsidence under the lateral flowline support and due to extreme snow load behind the well house on top of the lateral flowline.	Fittings/Seals/ Connections	1. Conduct an analysis to determine the potential cause(s) of the S-riser failure. 2. Take action to relieve the snow loading condition on the 2M-1 flowline and other wells on 2M pad as necessary. 3. Prepare a work order for engineering to initiate a design for an improved lateral flowline piping support system for 2M pad.
KR-0019401	7/12/2000	2M	424.2	Produced Water-100%	Inside the pig launcher/receiver building a multi-port gauge valve failed. The bonnet and valve handle assembly had parted from the body of the gauge valve. The multi-port gauge valve (MPGV) was a welded component of a temporary choke pipe spool used for filling the DS-2N MI pipeline with water for temporary water injection during summer months.	Fittings/Seals/ Connections	Removed temporary choke spool and replaced with permanent spool. The failed components of the valve have been collected and will be forwarded to Phillips-Bartesville for failure analysis.
KR-0024501	9/1/2000	CPF3	90	Crude-25%, Hydraulic Fluid-10%, Motor Oil-10%, Produced Water-10%, Seawater-10%, Freshwater-25%, Glycol-10%	The liner in the Module Sump Drain (MSD) pit was discovered to be torn. When the liner was removed the pit was full of water that had a sheen on it. Volume of contamination in the pit could not be determined until the pit had been dewatered.	Pipe/Flowlines/ Hardline	Reinstall pit liner and raise subgrade.
KR-0029302	10/19/2000	CPF1	420	Crude-1%, Produced Water-98%, Other-1%	Root valve on drain tank failed.	Pipe/Flowlines/ Hardline	Take tank out of service and replace root valve - FWR # L908639 to replace root valves.

TABLE C-1 (CONTINUED): KUPARUK SPILL HISTORY

Spill #	Date	Location	Volume (Gal)	Product	Cause Explanation	Source	Corrective Action
KR-0033701	12/2/2000	CPF3	150	Crude-75%, Produced Water-25%	Pump seal failed - leaking seal on "b" wet oil booster pump.	Fittings/Seals/ Connections	1. Install the new seals in the "B" WOBP ASAP. Install the new type seals into WOBP's "A&C" as soon as they are received. 2. Check the primary separator using the infra red scanner to determine if there is a build up of sand in the vessel that could be carrying over to the WOBP's. 3. Review and evaluate the PM's for the block valves on the WOBP's.
KR-0036201	12/27/2000	1G	70	Crude-20%, Produced Water-80%	6" well pipeline leaked onto gravel road and pad, suspect internal corrosion.	Pipe/Flowlines/ Hardline	Radiographic inspections were conducted on 12-29-00 at several points along the 1G, Well 8 pipeline. A full inspection is presently being conducted on the line. The results of the inspections and other past information will be used to develop a repair plan for this line and will be considered for a potential action plan for lines in similar service at 1G and fieldwide.
WN-011501	1/15/2001	2N	80	Diesel-100%	Leaking check valve	Tanks	Replaced faulty check valve
KR-0110501	4/15/2001	CPF1	92400	Produced Water-100%	External corrosion on buried crossing	Pipe/Flowlines/ Hardline	Line was isolated. Cause is under investigation.
KR-0122201	8/10/2001	CPF3	60	Crude-1%, Produced Water-99%	Sump Overflow	Sumps	--
WN-0123101	8/19/2001	2N	630	Downhole cuttings-20%, Drill mud-80%	Tee on rig side of injection line washed out.	Pumps	Replaced tee with heavy duty tee
KR-0124901	9/6/2001	CPF3	167	Lube Oil-100%	A failure of the Frame 5 Generator Gearbox lube oil vent piping caused a lube oil leak in module 329. Oil leaked through soffit floor into a lined secondary containment dike (150 gals) and onto gravel pad (17 gals). Frame 5 Generator was shut down and Lube oil vent piping repaired. Alaska Clean Seas was contacted and contaminated gravel was removed.	Compressor Vents/ Module Vents	1. Assess the entire unit for vibration failure areas and mitigate these areas with the use of flex piping or extra supports. Anything identified will be replaced and or modified during the next outage. 2. Review historical vibration readings and determine at what speed the turbine should be run to minimize vibration. 3. Evaluate and make changes to the secondary containment area to prevent spillage to the gravel pad should another failure occur.

TABLE C-1 (CONTINUED): KUPARUK SPILL HISTORY

Spill #	Date	Location	Volume (Gal)	Product	Cause Explanation	Source	Corrective Action
KR-0133401	11/30/2001	1E	1259	Crude-9%, Produced Water-91%	Material leaked from an eroded area on a static mixer - 3" diameter piping.	Pipe/Flowlines/ Hardline	1. Evaluate the sizing of the test separator Y-strainer screens to reduce the accumulation of debris upstream of the static mixers. 2. Conduct an NDE inspection of the other static mixers in the field. Include follow up inspections during routine annual drill site NDE inspections.
WN-0133701	12/3/2001	CPF2	420	Diesel-100%	Gasket on tanker truck pump flange failed while offloading diesel into holding tank.	Fittings/Seals/ Connections	Replaced gasket.
WN-025401	2/23/2002	CPF1	149	Diesel-100%	Overfilled third compartment of tanker.	Heavy Equip/Mobile Equip/Vehicles	Additional field training.
KR-029701	4/7/2002	2A	1200	Crude-8%, Produced Water-92%	Caused by corrosion/erosion. Observed a pin-hole sized leak around a Cosasco fitting weld.	Pipe/Flowlines/ Hardline	Valves were closed at manifold building and well. Leak stopped. Depressured flowline and blinded for repairs. The failed equipment was removed for inspection and investigation.
WN-0212603	5/6/2002	3F	100	Diesel-100%	A gasket on a Tioga heater fuel filter failed allowing material to discharge	Fittings/Seals/ Connections	Evaluate filter gaskets on fuel filters
KR-0222401	8/12/2002	KOC	75	Hydraulic Fluid-100%	The crane operator was driving the crane back to the equipment storage tent when the operator noticed that the equipment was leaking hydraulic fluid. The operator also noticed that fluid had leaked for approx. 1/4 mile. A broken hydraulic pump housing was found to be the cause of the spill.	Heavy Equip/Mobile Equip/Vehicles	Employee training and procedures. Fix the pump on the crane, install a larger containment on the crane.
WN-0224101	8/29/2002	3B	672	Diesel-100%	Driver got too close to the soft shoulder of the road and overturned on the tundra.	Heavy Equip/Mobile Equip/Vehicles	Communicate road position and soft shoulder issues to all drivers. Review and revise LRS Driving Policy.
KR-0232001	11/16/2002	CPF2	84	Lube Oil-100%	Crankcase on 'B' Gas Injection Compressor failed, causing 84 gallons of lube oil to spill to the module floor. An investigation was conducted and revealed that a counterweight had come loose inside the machine, came into contact with one of the two internal connecting rods, and released through the top inspection cover of the compressor's crankcase. Further investigation revealed that the two studs holding the counterweight in place failed due to fatigue. The unit is equipped with vibration probes, accelerometers and velocity probes. There was no indication of a problem from any of these sensors prior to the failure.	Fittings/Seals/ Connections	This gas injection compressor was one of three that were upgraded for the gas handling expansion project this year. The other two gas injection compressors, units 'A' and 'C', were shut down and inspected following the incident. No problems were found with either machine.

TABLE C-1 (CONTINUED): KUPARUK SPILL HISTORY

Spill #	Date	Location	Volume (Gal)	Product	Cause Explanation	Source	Corrective Action
WN-0232501	11/21/2002	1C	168	Gel-Guar Gum/Diesel-8%, Seawater-92%	Computer failure caused pump to prematurely shut down causing the fluid to overflow the pump and containment. 84 gals spilled to secondary containment, ~84 gals spilled to pad.	Pumps	Manual methods will be used to backup the computer to ensure that the computer can not shut down the pump.
KR-0235201	12/18/2002	ROAD	12119	Hydraulic Fluid-1%, Muds and cuttings-99%	Peak maxihaul left roadway and rolled over, spilling 60 yds. muds/cuttings (2000 sq. ft.), 2 gal. hydraulic fluid (12 sq. ft),and 1 quart diesel (6 sq. ft) to tundra. Deteriorating weather, truck off road, speed excessive for conditions.	Heavy Equip/Mobile Equip/Vehicles	Vehicle/trailers inspected for mechanical problems. None found, investigation concludes loss of control led to incident. Taproot investigation pending.
KR-038901	3/30/2003	2V	500	Produced Water-100%	Bleed fitting on instrument valve that pilot is attached to was found in the open position. The bleed fitting was used during some maintenance in early March. It appears the bleed fitting developed an ice plug during the maintenance and was assumed to be closed. When the ice plug thawed, produced water leaked out, causing the spill.	Pipe/Flowlines/ Hardline	Depressured flowline and blocked in gate valve. Investigated cause. Closed bleed, cleaned up spill and brought well back onto injection.
KR-0310301	4/13/2003	1H	10920	Produced Water-100%	Failed O-ring seal on pig receiver while pigging produced water line. Spilled material directly under building and into snow covered pigging pit. Spilled material is 99.78% produced water (10896 gal) and 0.22% crude (24 gal).	Fittings/Seals/ Connections	Evaluate receiver for potential repairs.
KR-0313701	5/17/2003	2G	93	Diesel-16% Hydraulic Fluid-82% Lube Oil-1%	A Grove RT 750 crane moved too close to the shoulder on an access road between reserve pits on 2G Pad. The shoulder collapsed and the crane rolled over.	Heavy Equip/Mobile Equip/Vehicles	Review all fire lanes for proper width and proper slope and repair to specs as necessary. Brief operators to be aware of icy conditions prior to starting work and call for loader to scratch the area. Review SOPs with all crane operators and emphasize the need to use a spotter when necessary or address any other hazards prior to proceeding.
WN-0322001	8/8/2003	1G access road	140	Hydraulic Fluid-100%	Employee opened valve on a tote mistakenly thinking that he had closed it. During transport, the cam lock cap vibrated off allowing fluid to drain out of tote.	Fittings/Seals/ Connections	Communicate to employees that drain valves on totes are different than a normal ball valve, and the ears are to be wired shut to prevent cam lock cap from vibrating loose.

TABLE C-1 (CONTINUED): KUPARUK SPILL HISTORY

Spill #	Date	Location	Volume (Gal)	Product	Cause Explanation	Source	Corrective Action
KR-045901	2/28/2004	CPF1	800	Naphtha-100%	Tubing failure from the overhead condenser.	Pipe/Flowlines/ Hardline	1. Develop a near term solution to prevent freezing of overhead condenser tubes over the next few months until spring arrives. Complete - Operational procedures have been changed to pump methanol to the overhead condenser every 12 hours 2. Inspect overhead condenser tubes with an eddy current probe provided by Testex, Inc. This will further verify the mechanical integrity of the tubes. 3. Develop a long term engineering solution (e.g. air temperature monitoring, variable speed fans, etc.) to prevent tubes from freezing. 4. Communicate lessons learned from this hydrate plugging problem to operations at a Monthly Incident Review meeting.
KR-047702	3/17/2004	2D	1189	Crude-20%, Produced Water-80%	Poss ble weld failure	Pipe/Flowlines/ Hardline	Evaluate possibility of using a PM to initiate periodic review of snow loading, especially at the locations pre-identified in the 2003 engineering report. Pursue equipment alternatives such as fire trucks for snow removal to supplement vacuum truck use. Evaluate cracked weld on 4" X 6" reducer to determine failure mechanism and provide recommendations as needed.
KR-048701	3/27/2004	CPF3	60	Produced Water-100%	Drain valve flush line burst either due to corrosion or freezing. The resulting rupture caused produced water, which is the fluid used for the flush, to leak from the rupture to the pad below the primary separator. Suspect corrosion due to static fluids in a "dead leg" area.	Pipe/Flowlines/ Hardline	Conducted a formal incident investigation.
KR-0411701	4/26/2004	2X	136	Produced Water-100%	A ball check on a grease fitting of a plug valve on a produced water injection line failed and started leaking.	Fittings/Seals/ Connections	To be determined.
KR-0413302	5/12/2004	2M	2545	Crude-30%, Produced Water-70%	Mechanical failure of pressure gauge on a 12-inch pipeline (Heater Production Outlet line) resulting in freezing.	Pipe/Flowlines/ Hardline	The line was shut in and the gauge replaced. An incident investigation was completed.
KR-0413501	5/14/2004	CPF3	678	Crude-1%, Seawater-99%	PSV on the seawater injection pump malfunctioned.	Pumps	Blocked in the PSV until it reset.

TABLE C-1 (CONTINUED): KUPARUK SPILL HISTORY

Spill #	Date	Location	Volume (Gal)	Product	Cause Explanation	Source	Corrective Action
KR-0415701	6/5/2004	3K	100	Crude-4%, Diesel-2%, Produced Water-94%	Leaking flange was discovered on Produced Water Injection line.	Flanges	Well was shut-in, line was depressured and drained. An incident investigation will be conducted.
KR-0419701	7/15/2004	2M	252	Crude-1%, Produced Water-99%	O-ring failure on pig receiver.	Fittings/Seals/ Connections	Replaced o-ring. An incident investigation was initiated.
WN-0422601	8/13/2004	1E	1050	Mineral Oil Based Drilling-100%	Valve unintentionally left in partially open position which caused tank to overflow.	Fittings/Seals/ Connections	1. Install High-level switch on bleed tank with audio and visual alarms. 2. Perform audits of Spill Drills between now and 09/14/04 3. Review and modify injection skid checklist to include size of secondary containment. 4. Communicate with all Rig 141 employees the need to keep rainwater and snow out of secondary containments. 5. DDI Management to generate audit form for operational procedures in place in Injection skid Unit. 6. Rig supervisors to include Injection skid unit in their STOP Supervisor walkthroughs.
WN-0424801	9/4/2004	1E	168	Mineral Oil Based Drilling-100%	Valve on the injection skid overflow line was not closed tightly allowing very slow leak-by of oil based mud.	Tanks	1. Install a camera system in the pump room so that the equipment can be observed via a monitor placed in the control room. 2. Construct a tank volume indicator to give the operator a visual indication of how many barrels are in the bleed tank 3. Discuss this incident with all crews during safety meetings. Discuss checklists, fluid transfers, SOP's and STOP audits during the meetings along with the hazards that need to be recognized when performing this type of operation 4. Modify Injection Skid Operating Procedure to state that the Bleed Tank shall be used as a bleed tank only. Any other use of the tank shall be approved by the CPAI Rig Supervisor prior to use. Perform a documented review of this modification to the procedure with injection skid operators. 5. CPAI Rig Supervisors will discuss with crews the need for management to be included in discussions regarding the performance of non-routine tasks.

TABLE C-1 (CONTINUED): KUPARUK SPILL HISTORY

Spill #	Date	Location	Volume (Gal)	Product	Cause Explanation	Source	Corrective Action
KR-051601	1/16/2005	2Z	644	Produced Water-100%	Failed bleeder valve on pig receiver door closure.	Fittings/Seals/ Connections	Revise the existing mechanical integrity inspection procedure for pig L/R closures to include an inspection of the pressure warning device. Establish a recurring PM inspection using the updated mechanical integrity inspection procedure. Revise existing SOP for opening and closing pig L/R to include inspection of the bleeder and condition of the thermal relief path check valve. Provide appropriate spare parts lists for the Materials Planners to update in SAP per tag number for each pig launcher/receiver and closure device. Establish appropriate stocking levels of soft goods and other components per engineering recommendations. Provide training for appropriate DS operation and maintenance personnel on the updated pig L/R opening and closing procedure. Re-evaluate thermal relief path design and implement plan for replacement as required.
KR-058501	3/26/2005	2H	51198	Produced Water-70%, Seawater-30%	Spill caused by hole in pipe due to internal corrosion. Note: the volume estimate was reduced based on determination of the hole size, flow rate and analysis of pressure data leading up to the event.	Pipe/Flowlines/ Hardline	1. As part of a technical Root Cause Failure Analysis (RCFA) evaluate and recommend modifications to the existing internal inspection program that would minimize the possibility of reoccurrence of this type of failure. 2. As part of a RCFA evaluate and implement modifications to the existing mitigation (chemicals) and monitoring (probes, coupons) program that would minimize the possibility of reoccurrence of this type of failure. 3. As part of a RCFA evaluate and recommend modifications to the current pigging program including pig types, frequency, measuring and meeting minimum velocities, and mechanical integrity of pigging systems. 4. Evaluate and recommend improvements to instrumented leak detection systems for cross country water injection lines. 5. Determine what additional inspection and/or repair is required prior to bringing the 2K water injection line back into service.

TABLE C-1 (CONTINUED): KUPARUK SPILL HISTORY

Spill #	Date	Location	Volume (Gal)	Product	Cause Explanation	Source	Corrective Action
KR-0514201	5/22/2005	CPF2	75	Lube Oil-100%	The lube oil system was modified during a facility shutdown with the addition of a 5 hp blower on the demister tank. The blower was designed to create a slight negative pressure in the lube oil system to decrease lube oil leaks on the skid and to centralize the lube oil atmospheric ventilation system. The demister blower had been installed but E&I had not been completed yet. The blower was in bypass and the demister tank was in service. In an attempt to lower the lube oil system pressure, the lube oil demister bypass valve was opened allowing most of the flow to bypass the demister tank. Discussions surrounding the opening of the bypass valve concentrated on lowering the elevated lube oil system pressure. Risks of lube oil blow-by were not discussed.	Compressor Vents/ Module Vents	1. Complete installation and commissioning of the lube oil demister blower. 2. Complete MOC and Process Safety Analysis, and Operator training for the lube oil demister system.
KR-0517901	6/28/2005	KIC	420	Freshwater w/tr hydrocarb-100%	400-bbl upright was delivered to Washbay for cleaning. Contents of the upright tank were misrepresented and employees did not strap or visually inspect the tank prior to emptying. Additionally, the gauge on the supersucker used to recovered material showed that it was 3/4 full when in fact it was much fuller. As the upright tank was opened, the supersucker was unable to pick up the material. Approximately 10 bbls of fluid spilled out of containment, and onto the gravel pad. An estimated 2 gallons of fluid with a light sheen contacted tundra.	Tanks	The work crew will be retrained on the Tank Cleaning procedure. For future work, containment will be utilized for outside cleaning or the tank will be brought into the washbay.
KR-0519301	7/12/2005	1D	1603	Diesel-100%	33-38 bbls diesel and unknown volume of produced water from wellhead casing leak	Pipe/Flowlines/ Hardline	1. Identify and conduct well integrity diagnostics on wells with monobore design (MIT & Caliper). 2. Develop an action plan to repair or abandon monobore wells that have failed integrity testing. 3. Evaluate how drilling completion reports are being transferred to the CPAI wells group. 4. Communicate the need to report all spills to security immediately, regardless of an accurate spill estimate.
WN-0521501	8/3/2005	1E	153.5	Oil based drilling mud-100%	Expansion boot failure on discharge line of transfer pump in rock washer.	Pumps	Expansion boot replaced.

TABLE C-1 (CONTINUED): KUPARUK SPILL HISTORY

Spill #	Date	Location	Volume (Gal)	Product	Cause Explanation	Source	Corrective Action
KR-0522101	8/9/2005	2B	483	Produced Water-74%, Seawater-26%	Internal corrosion on inside radius of elbow on the 2" pig launch receiver bypass line.	Pipe/Flowlines/ Hardline	1. Following completion of the technical analysis, recommend changes to the corrosion mitigation and surveillance programs. 2. When analysis is complete, determine if a mechanical piping change is required to prevent recurrence. 3. Work with Security and Alaska Clean Seas (ACS) to address notification protocol including a change to ACS (Kuparuk) SOP of forwarding telephones to ACS (Prudhoe).
WN-0523201	8/20/2005	1E	132	Oil based drilling mud-100%	While back reaming out of hole 6" line on mud bucket failed under rig floor.	Transfer Hoses	Replaced hose and inspected the failed hose for poss ble cause. Hose had been in service approximately 6 months.
WN-0533501	12/1/2005	2D	157	Diesel-100%	During CTU fill cleanout, diesel returns circulating to open top flow back tanks overfilled to overflow the tank due to poor communication on the volume in the tank.	Tanks	1. Inspect all open top tanks in use in NSOD. Verify level markings do not indicate volumes greater than actual capacity. Correct the markings on tanks that could lead to an overflow. Mark the Maximum Capacity of all tanks on the exterior of the tanks near the access points. 2. Rewrite the Schlumberger CTU flow-back procedure to include: • A discussion of radio communications and the need to use repeat-back of critical information. • A discussion of the elements to be discussed during the pre-job brief and specifically a discussion of means of determining and communicating maximum tank capacities throughout crew. • A discussion of expectations for crew member communication when relieving one another specifically including a discussion of verification of volume information. • A discussion of the use of the rig-up diagram and the need to document the maximum volumes of the tanks being used. 3. Communicate the above mentioned rewrite with specific discussion of all changes to all Schlumberger CT crews currently working or anticipated to be working on ConocoPhillips leases. 4. Share this report with all CT crews.

TABLE C-1 (CONTINUED): KUPARUK SPILL HISTORY

Spill #	Date	Location	Volume (Gal)	Product	Cause Explanation	Source	Corrective Action
KR-0535901	12/25/2005	CPF1	630	Crude-3%, Produced Water-97%	The outboard seal on waterflood injection pump P-2202B failed allowing Produced Water to enter the seal flush reservoir. This caused the seal flush reservoir to overflow onto the floor of Module 2201.	Fittings/Seals/ Connections	Pump was shut down and isolated to eliminate source of spill. CPAI initiated an incident investigation to determine causal factors and remedial actions on 12/26/05. The area of the module where the produced water leaked out will be resealed. The failed pump seal will be analyzed to determine the cause of failure. The preventative maintenance (PM) history of the pump will be reviewed and the PM schedule revised, if necessary.
KR-060901	1/9/2006	CPF1	150	Contaminated Fresh Water-100%	Piston Failure on CFW pump	Pumps	1. Maintenance will develop a plan for determination of ceramic plunger reliability. 2. Evaluate upgrading the pump case bed drain system. Items to consider include; increasing containment volume, increasing pneumatic sump pump capacity, or build a permanent module sump to catch all module drains and provide high level alarm and injection pump shutdown and increase sump pump suction and discharge line size. 3. Evaluate installing a CFW suction line remote operated valve inside the CFW module with associated instrumentation and shut down logic. 4. Evaluate installing vents at high points of the pump liquid ends to facilitate bleeding of air each time the pump is drained. 5. Change Setcim alarms;§ CFW water leak detect trouble alarm (XA-10260-TR) from “Log Only” to “Advisory” status. § CFW water leak detect alarm (XA-10260) from “Log Only” to “Critical” status. 6. Identify all locations in the CPF1 area that have leak detect strips and verify alarms a prioritized properly in Setcim.
WN-061801	1/18/2006	1D	67	Diesel-100%	Diesel found on pad between well 113 and well 114. Also found in cellar of 114.	Unknown	None

TABLE C-1 (CONTINUED): KUPARUK SPILL HISTORY

Spill #	Date	Location	Volume (Gal)	Product	Cause Explanation	Source	Corrective Action
KR-062901	1/29/2006	2K	210	Produced Water-20%, Methanol-80%	Partially frozen 2" water injection flowline split at an e bow.	Pipe/Flowlines/ Hardline	Ensure that pump truck operators have a portable radio on hand, or install a permanent radio that can be heard above the pump background noise. Evaluate changes to administrative controls and /or engineering design options that will help prevent freezing of the DS 2K injection well 2" flow lines.
KR-066802	3/9/2006	2M	700	Produced Water-100%	Internal corrosion	Pipe/Flowlines/ Hardline	1. Develop 3 Phase flow models for looped lines to indicate low fluid velocity segments. 2. Detect and remediate low corrosion inhibitor flow conditions in a timely fashion. Review and revise existing procedures to insure that they include processes for early detection and correction of problems. 3. Re-emphasize the importance of maintaining corrosion inhibitor target flow rates with operations personnel. 4. Create elevation profile drawings of cross country lines to ensure low points are included in inspections. 5. Conduct a Physical Cause Analysis and RCFA which includes participation from other BU's within ConocoPhillips. 6. Re-evaluate type and placement of corrosion monitoring devices for corrosion on inhibited produced crude lines.
KR-069601	4/6/2006	ROAD	2608	Contaminated Cuttings-100%	Truck drove off the road when the driver reached for his water bottle.	Heavy Equip/Mobile Equip/Vehicles	Counseled driver
KR-0612701	5/7/2006	2Z	400	Crude-100%	Open top tank (presumed to be empty) spilled contents when it turned on it's side while being loaded on a trailer for transport	Tanks	1. Communicate to the AES Wells Support Group it is AES Policy to strap all portable tanks for volume before they are moved. 2. Communicate to the AES Wells Support Group the AES recommended practice to move wheeled tanks with a winch tractor rather than a bed truck, whenever poss ble. 3. Any tanks that do not pick dead-center will have the tongues modified. 4. All bed truck drivers in the Wells Support Group will review this IR.

TABLE C-1 (CONTINUED): KUPARUK SPILL HISTORY

Spill #	Date	Location	Volume (Gal)	Product	Cause Explanation	Source	Corrective Action
KR-0615901	6/8/2006	2U	100	Diesel-100%	Fuel truck driver hooked up to the "diesel day tank" instead of the "diesel storage tank" line. Diesel day tank overflowed through the vent on the roof.	Tanks	1. Improve new driver training and qualifying to include: a. Dead-leg brace identification b. Tracing piping systems and delivery points c. Ask for assistance for verification d. Review practical training2. Lower the "diesel storage tank fill/drain" sign so it is no longer partially obscured by the "truck loading only" sign at 2U and all other pads of similar configuration. Make new signs to read "Max Capacity 225 gallons" and attach below the "diesel pump day tank fuel fill" signs at 2U and all other pads of similar configuration.
KR-0616603	6/15/2006	2X	1128	Produced Water-100%	Corrosion related failure of 2X-08 produced water flowline.	Pipe/Flowlines/ Hardline	1. Ensure future well line internal corrosion inspection records are reviewed for external corrosion implications and reconciled with previous CUI inspection results. 2. Prior to embarking on the well line CUI interval inspection survey, the Coordinator will review the previous CUI inspection records to ensure all previously uninspected CUIA's have been inspected.
KR-0617201	6/21/2006	3B	252.5	Produced Water-100%	Failed fitting on produced water header caused 252 gal spill inside building and 1/2 gal spill outside of building.	Fittings/Seals/ Connections	Other fittings were inspected to ensure that the problem will not reoccur.
KR-0620101	7/20/2006	CPF1	120	Contaminated Fresh Water-100%	CFW pump packer rod failed, causing fluid to leak out of the pump cavity.	Pumps	Pump was shut down and valves were closed to stop the fluids from running onto the module floor.
KR-0624201	8/30/2006	CPF1	190	Produced Water-100%	PSV failure on pig launcher. Specific cause under investigation. Following pigging operation, PSV appears to have become unseated, allowing fluid to leak into floor sump. Floor sump overfilled.	Pipe/Flowlines/ Hardline	1. Replace Thermal PSV 2. Consider redesign of thermal relief discharge. (check valves, process tie-in, isolation valve) 3. Re-commission MSD sump overflow system 4. Identify other thermal PSV installations with discharge to MSDs for potential redesign.
KR-0630102	10/28/2006	1J	90	Produced Water-100%	Failed gasket on DP cell caused spray release of produced water.	Fittings/Seals/ Connections	Replaced gasket.

TABLE C-1 (CONTINUED): KUPARUK SPILL HISTORY

Spill #	Date	Location	Volume (Gal)	Product	Cause Explanation	Source	Corrective Action
KR-071301	1/13/2007	CPF1	3249	Produced Water-100%	CPF1 personnel discovered a small stream of produced water draining into the secondary separator sandjet tank. The tank had overfilled into the secondary containment, and subsequently also onto the gravel pad surrounding the open top tank. The fluid was determined to be leaking through four closed valves in the piping system that is used to drain sand jet fluids from the secondary separator into this tank.	Tanks	1. Service or replace leaking block valves on the secondary separator drain system. 2. Establish a PM to service block valves on sand jet drain systems. 3. Modify tank cover to allow visual confirmation of flow to the tank. 4. Evaluate installation of high level alarms or other instrumentation on the secondary separator sand jet tank. 5. Add secondary separator sand jet tank secondary containment to the daily inspection check list. 6. Survey and evaluate all other instances where we rely on closed valves to prevent an atmospheric release. 7. Review The Open Ended Valve Capping Valve Policy and determine whether it should be expanded in scope to address fixed drain systems. Consider additional safeguards and controls that may be necessary where we rely solely on a closed valve(s) to prevent a release to atmosphere. 8. Review the 2007 CPF-1 Sand jet Consolidation design in light of this incident.
KR-073501	2/4/2007	CPF1	486	Crude-99%, Produced Water-1%	pump failure	Pumps	Visqueen anchored beneath the module to capture any dripping crude oil. Repair/Replace P-101A as required. Modify nitrogen back up supply to isolate P-101A & P-101B Consider separating backup nitrogen supply on other operations critical pumps (crude oil boosters). Re-evaluate vibration monitoring as an option for detecting early symptoms of pump problems. Raise priority on pre-existing project to reduce potential cavitation in system (PMO #3520425). Review additional leak detection options for divert tank module (sump). Repair or replace the oil leak detection strip in the divert tank module. Review causal factor with vendor and discuss protocols to prevent reoccurrence.
3785	3/19/2007	1j	126	100% Oil based drilling mud	While preparing to stand back a stand of drill pipe, the pipe was partially backed out with the pumps still running.	Unknown (use only for non-reportable)	

TABLE C-1 (CONTINUED): KUPARUK SPILL HISTORY

Spill #	Date	Location	Volume (Gal)	Product	Cause Explanation	Source	Corrective Action
3805	3/19/2007	CPF2	105	100% Produced Water	Secondary stem seal failed.	Fittings/seals/connections	Incident investigation corrective measures: 1. Investigate further the valve seal failure, re-evaluate the four corners pig module installation, and provide a recommendation for preferred valves to be used in this service. 2. Seal the open joint between module walls and the module floor containment edge. 3. Install leak detection in four corners pig module. Identify poss ble alternatives for leak detection communication versus a low voltage communications cable, such as wireless transmitters. Provide recommendation for installation.
3826	3/28/2007	2T	87	100% Cortron RU-276	Fluid vented from the corrosion inhibitor tank and less than one pint misted to the pad and 93 gallons to containment. 3/30 revised volume to 87 gallons - 81 in containment and 6 to pad.	Tanks	
3864	4/5/2007	3K	105	100% Diesel	Surface casing leak.	Pipe/flowlines/hardlines	Incident investigation corrective measures: 1. Install wireless transmitters for annular pressure monitoring on waivered wells, including provisions for pressure alarms as appropriate. Consider expanding to all wells field wide, starting with problem wells. 2. Provide refresher of well operating guidelines, thermal expansion effects of fluid packed wells, clear definition, expectation and response to conservation orders 494 & 495. The training should also include Kuparuk examples that illustrate the variability in 1) the time required to start experiencing a thermal pressure increase, 2) the rate of pressure increase, and 3) the time required to reach thermal equilibrium. 3. Reinforce the expectation that if circumstances are such that you are unable to monitor a given well to ensure annular pressures are within limits, leave it shut-in.

TABLE C-1 (CONTINUED): KUPARUK SPILL HISTORY

Spill #	Date	Location	Volume (Gal)	Product	Cause Explanation	Source	Corrective Action
3885	4/15/2007	CPF3	714	25% Produced Water, 75% Seawater	Leak on the injection pump recycle header.	Pipe/flowlines/hardlines	1. Replace the entire sw recycle line per corrosion group recommendations. 2. Evaluate, and implement as appropriate, options for mitigating further corrosion in this and similar piping systems. 3. Evaluate the facility piping corrosion program in light of this leak, and adjust as appropriate. 4. Replace leaking valves to improve pw/sw isolation. 5. Review/critique the response from an operational perspective, and reinforce the value of communication, coordination, the use of exclusion zones, etc.
3905	4/19/2007	3C	350	100% Diesel	Shut in seawater injection line filled with freeze protect diesel. Flowline sprayed diesel in three locations in to the 3c reserve pit.	Pipe/flowlines/hardlines	1. Inspect the failed well line to determine/verify the corrosion mechanism. Note: inspection indicated the leak was caused by internal under-deposit corrosion. 2. Review the well line integrity program in light of this failure, and adjust as appropriate. 3. Review inspection history for wells 3c-5 and 14 to determine if additional inspection is needed and to determine their condition and fitness-for-service. Note: a repair recommendation was issued for 3c-14 based on this recent inspection effort.
3964	5/20/2007	1F	126	100% Glycol	Sight glass failure on line heater glycol bath and expansion tank.	Tanks	1. Initiate design effort, cost and plan to tie setcim trouble alarms into line heaters not currently equipped field wide. 2. Review the sight glass spill potential in 3 consecutive facility safety meetings with a goal of increasing spill potential awareness and the continued need to inspect these type devices for leaks during normal rounds. 3. Issue field wide environmental bulletin communicating sight glass spill potential wherever sight glasses are used.
4045	6/17/2007	1J	3,990.00	100% Drilling Mud	Mud collected in the cellar box due to a plugged return line during drilling. The cellar box overfilled and ran over into containment.	Pipe/flowlines/hardlines	TBD

TABLE C-1 (CONTINUED): KUPARUK SPILL HISTORY

Spill #	Date	Location	Volume (Gal)	Product	Cause Explanation	Source	Corrective Action
4184	8/4/2007	CPF2	177	100% IP Arctic Drag Reducing Agent (DRA)	Operator accidently bumped a valve which caused the tank to overfill.	Tanks	1. Develop a checklist and signoff sheet that will be used during weekly iso swaps and any other time there is a change of status in the iso set up or valving in the dra module. Initiate change log to emphasize this procedure. 2. Color code and clearly label the lines and valves in the dra module. Update and post a schematic of the piping and valve configuration with the new color coding. 3. Change the 4 critical valves (west ISO suction, west ISO recycle, east ISO suction, and east ISO recycle) to lockable ball valves. Provide the securing device with affixed tags for each valve. Initiate change log to emphasize the securing procedure. 4. Remove the historic air sparging piping and valves to a point away from the booster pump and product piping manifold. 5. Install a wireless temperature sensor to be used as a high level indicator in the top hatch of each iso. This sensor output signal will be programmed into setcim as a critical high level alarm. 6. Place temporary portable containment under each iso to catch any product that has overflowed the iso hatch compartment. Install buckets under each compartment drain line. 7. For long term solution, evaluate options and install either a level switch or a continuous readout level indication that can be easily mounted and removed from the isos. The preferred method would be for the instrumentation to provide a continuous real time level indication in the control room and also allow automatic shut down of the booster pumps at high level alarm. 8. Evaluate the cost and options for a long term method of providing a maintainable spill containment that is functional for all seasons.

TABLE C-1 (CONTINUED): KUPARUK SPILL HISTORY

Spill #	Date	Location	Volume (Gal)	Product	Cause Explanation	Source	Corrective Action
4186	8/5/2007	Road	65	100% Diesel	Fuel belly tank underneath a vac truck came loose spilling fuel as it dragged on the road.	Heavy equip/mobile equip/vehicles	1. All trucks in service with a similar tank support set up will be modified to strengthen the support of belly tanks. 2. The truck manufacturer will be contacted to request input on options for the modification to the tank supports.
4284	9/29/2007	1E	55	100% Diesel	Work area was left unattended and the tank overfilled.	Tanks	
4344	10/28/2007	CPF2	250	100% Produced Water	Seal failure on the production side of the water injection pump	Fittings/seals/connections	
4464	12/16/2007	2V	4,284.00	33% Crude Cil, 67% Produced Water	External corrosion	Pipe/flowlines/hardlines	1. Repair the line by installing an engineered sleeve. 2. Perform a physical cause analysis to review corrosion mechanisms and current inspection criteria and schedule for improvement. 3. Evaluate the saddle at this location to determine if the design is unique. Implement a strategy to address issues identified that could be present at other saddles. 4. Evaluate all new saddle designs to address avoidance of chafing and moisture accumulation.
4554	1/17/2008	STP	95	60% Triethylene Glycol, 40% Fresh Water	External corrosion on the glycol piping to heater	Pipe/flowlines/hardlines	1. Remove and clean tubes for ndt testing of tubes 2. Remove external casing on the other side of the heater, inspect and determine if similar corrosion is present 3. Remove external casing on the other two heater to determine if similar problems exist 4. Have corroded area analyzed to determine failure mechanism and come up with action plan for the other two heaters 5. Repair the corroded tube
4560	1/18/2008	3F	140	100% Produced Water	Fitting failure on produced water header	Fittings/seals/connections	
4593	1/31/2008	1Y	120	91% Produced Water, 9% Crude Oil, 0% Other	Line split due to ice plug. Line shut in during severe weather, and froze prior to re-start. During warm up activities, release was discovered. Spill casue related to line split caused by expansion of freezing water in the line after it was shut in.	Pipe/flowlines/hardlines	

TABLE C-1 (CONTINUED): KUPARUK SPILL HISTORY

Spill #	Date	Location	Volume (Gal)	Product	Cause Explanation	Source	Corrective Action
4813	4/17/2008	2C	180	100% Corrosion Inhibitor	During a transfer from truck to tank, operator allowed tank to overfill.	Tanks	1. Supervisor to share incident at toolbox and weekly safety meetings. 2. Modify spac requiring only one tank to be filled at a time. 3. Label valves (open/closed), flow direction of product on piping and install a placard on tanks reflecting one tank to be filled at a time.
4822	4/22/2008	2L	110	100% Diesel	Leaking camlock - missing gasket.	Valves	Replaced gasket.
4938	6/9/2008	3M	70	100% Corrosion Inhibitor	Vent valve was opened	Tanks	
5009	7/21/2008	CPF1	120	100% Produced Water	High point/pressure bleed washed out. Valve leaked by due to worn out sealing surface caused by solids in the produced water.	Valves	
5016	7/28/2008	KCS	336	100% Brine	Employee mis-read straping tape causing him to believe the tank had sufficient room for his load. Ended up overfilling tank.	Tanks	1. Define an observation process for fluid transfer tasks. 2. Develop a transfer best practices presentation and present at three consecutive weekly safety meetings. 3. Complete six audits in the next three months on fluid transfers. 4. Install elbows on this tank and similarly situated tanks so that spill will go into containment.
5022	7/30/2008	1H	140	100% Hydraulic Fluid	Oil filter gasket failure on pony motor on vac truck 143-046-242-032 sprayed hydraulic oil inside the pony motor sump and onto the pad.	Heavy equip/mobile equip/vehicles	
5028	8/1/2008	CPF3	82.5	100% Other	Condensate from steam cleaning the produced water pipe was drained into the module sump. The suction screen in the module sump clogged causing an overflow into the msd overflow pit. Wind caught some fluids and misted them onto the pad.	Sumps	
5032	8/4/2008	CPF3	120	80% Produced Water, 20% Crude Oil	Pump switch failure on the msd sump resulting in spill of produced water/crude oil mixture	Sumps	

TABLE C-1 (CONTINUED): KUPARUK SPILL HISTORY

Spill #	Date	Location	Volume (Gal)	Product	Cause Explanation	Source	Corrective Action
5068	8/8/2008	KCS	100	100% Cortron RU-276	The operator overfilled a tank truck. The gauge indicated the tank was 3/4 full. The gauge was determined to be defective.	Heavy equip/mobile equip/vehicles	1. Advise vendor of the defects of the level gauge indicator and cease further procurement of equipment from said vendor. 2. Look into an aud ble/visual high level alarm to warn operator that tank is nearing capacity. 3. Research a 2 way electronic metering system that will work with the corrosion inhibitor transfer pump and process. 4. Review and update sop for chemical truck inspection and operation.
5150	10/14/2008	1D	136	100% Brine	Miscommunication between driver of mi skid and vac truck driver while transferring fluids. Hose was not hooked up to vac truck before transfer started.	Transfer hoses	A tap root analysis will be performed and preventative actions will be determined at that time.
5213	11/7/2008	Road	95	85% Drilling Mud, 10% Glycol, 4% Diesel, 1% Other	Driver was unable to negotiate curve under icy conditions	Heavy equip/mobile equip/vehicles	1. Put out field wide bulletin reminding drivers to look for changing road conditions. 2. Present a driving awareness/changing road conditions presentation for the next 3 weekly safety meetings.
5219	11/9/2008	CPF3	420	99% Seawater, 1% Crude Oil	More water was sent to the sump than the sump could handle, causing an overflow.	Sumps	A sand jet tank was placed into the secondary containment after clean up was complete in order to capture any future burps. This allows for easier clean up of the area.
5278	12/9/2008	CPF2	100	100% Triethylene Glycol	Packing failure on teg pump P128	Pumps	1. Install a placard on each pump case with the following: caution - when new packing is installed, packing glands may be intentionally loose. Adjustment will be required after initial startup. Contact facility mechanics.

TABLE C-1 (CONTINUED): KUPARUK SPILL HISTORY

Spill #	Date	Location	Volume (Gal)	Product	Cause Explanation	Source	Corrective Action
5318	12/25/2008	1L	94,920.00	99% Produced Water, 1% Crude Oil	Release occurred as a result of internal corrosion in a 6" produced water injection line. The release impacted the gravel pad. A very minor mist was released to the adjacent snow covered tundra. There was no penetration of the snow to the tundra as a result of the mist.	Pipe/flowlines/hardlines	1. Update the EPDRM As-Built process to clearly define the process and procedural steps that should be followed. 2. Perform a well line inspection schedule review for well lines that have undergone partial replacement and correct discrepancies. (field wide). 3. Conduct a gap analysis to identify areas for improvement in the process by which changes to piping, new or replacement, are clearly communicated to the corrosion group so that inspection requirements can be defined and implemented reliably. 4. Revise all applicable piping inspection interval survey guidelines to clearly identify how critical inspection scheduling parameters (such as date installed) are derived. 5. Evaluate and establish a best practice to address the added complexity of partial line replacements and the presence of various wall thicknesses to well line interval survey inspection scheduling, 6. Perform an engineering review of GKA well line pressure alarm systems in light of this leak and recommend actions to ensure these systems will function as intended. 7. Review and update design standards to ensure requirements for pressure based alarms systems are clearly defined and incorporate learning's from this incident. Update cpai criteria and specifications and standard details as deemed necessary by the review.
5387	2/3/2009	CPF1	6,930.00	100% Other	The leak location was a small split in the 12:00 position on the pipe. The pipe is scheduled for replacment early 2009.	Pipe/flowlines/hardlines	The pipeline has been replaced with HDPE-lined, small-diameter pipe that should be impervious to corrosion and should have a higher velocity to prevent solids build-up.

TABLE C-1 (CONTINUED): KUPARUK SPILL HISTORY

Spill #	Date	Location	Volume (Gal)	Product	Cause Explanation	Source	Corrective Action
5467	3/3/2009	2M	85	100% Cortron RU-276	Corrosion inhibitor tank was overfilled due to restriced sight glass, causing erroneous readings. Product spilled out of the back of the building into an overflow drum, into secondary containmnent (55 gal), and onto the snow covered gravel pad (30 gal).	Tanks	Repaired sight glass on tank. 1. Review with chemical truck drivers to report any malfunctions in any part pf chemical transfer operation. 2. Conduct field audit of all chemical tank locations for proper labeling, valve placement and overflow drum locations and design. 3. Modify chemical truck operator guidelines to include ways to verify proper sight glass oepration, engine rpm's and no multi-tasking during fill operations. 4. Research and make recommendations for possible purchase ofinfrared gun to double check calibration during filling. 5. Inspect, clean and/or repair sight glass and bent lines on all 4 CI tanks 6. Improve or replace overflow duct system to overflow drum.
5513	3/22/2009	1L	9,450.00	100% Produced Water	At approximately 0245 hrs on 3/22, a produced water leak was discovered on injector 1L-16. The leak was from a failed pressure gauge on the 1L-16 well line inside the wellhead shelter. The well was shut in and the line depressurized. The produced water leaked out of the wellhead shelter onto the pad and into the reserve pit. None of the fluid that leaked left the pad.	Pipe/flowlines/hardlines	After the well was secured and the leak point identified, a new gauge was installed on the well line. The well was returned to produced water injection service at 0450 hrs on 3/22. An incident investigation was conducted.
5514	3/22/2009	CPF1	200	100% Produced Water	Seal failure on pump inside building.	Pumps	
5593	4/30/2009	1H	100	100% Hydraulic Fluid	Surface safety valve O-ring failure, causing 25 gal hydraulic oil to spill to well cellar area. An additional 75 gal discovered in well cellar area on 6/25/09.	Fittings/seals/connections	Well hydraulic system was repaired. Recommended remedial actions include 1) label the supply and return hydraulic tanks to be able to monitor volumes. This will help determine if there is a leak as well as the amount that may have leaked, and 2) add a section in setcim to update volumes on the hydraulic tanks, on the drill site morning reports.
5756	8/24/2009	1B	84	100% Produced Water	Mainly internal under-deposit corrosion with minor external corrosion combined, and verified by visual, UT and radiographic inspection.	Pipe/flowlines/hardlines	Install a sleeve over the leak area to bring the line back into service with a long term plan of full line replacement. Additional inspections were performed on the line to give us confidence in the integrity of the line to bring the line back into service. A long term plan for full ine replacement wil lbe issued.

TABLE C-1 (CONTINUED): KUPARUK SPILL HISTORY

Spill #	Date	Location	Volume (Gal)	Product	Cause Explanation	Source	Corrective Action
5758	8/25/2009	Road	78	100% Hydraulic Fluid	Hydraulic line failure on vac truck. After loading the vac truck, the operator energized the hydraulic system and drove to another drillsite. Because of the height of the hose tray, and the expanded metal sheet welded over the piping, the pipes could not readily be seen. The piping was secured in the hose tray by a steel saddle and steel clamp which over time had chafed a hole in the hydraulic supply line. Due to the design, and lack of vis bility, the leak went undetected.	Heavy equip/mobile equip/vehicles	Reconfigure the hydraulic system piping to run along the driver side of the tank similar to the other tankers that have been modified. Promulgate written directives requiring plug protection on all mobile equipment containing systems with drains. Directive will contain requirement to verify that plugs are in place prior to placing equipment in operation.
5829	10/23/2009	2A	60	30% Crude Oil, 70% Diesel	Line was shut in and isolated; during high pressure well integrity testing, fluid leaked past a valve and corroded elbow cracked.	Pipe/flowlines/hardlines	Inspect all gas lift lines at DS-2A. All gas lift lines at CPF-2 drillsites will be audited for small unsealed gaps in the insulation. If deficiencies are found, further corrosion inspection will be performed. To address the valve leak-by, standard procedures for well integrity testing will be analyzed and revised.
5876	11/26/2009	1E	630	42% Glycol, 58% Fresh Water	Glycol/water mixture (dowfrost heat transfer fluid) was evacuated to a small vac truck after hydrotesting a line. Some time later, fluid leaked by a butterfly valve and spilled out of the end of a hose that was attached to the tank. Spilled material was discovered by a passerby who was fueling equipment on pad.	Heavy equip/mobile equip/vehicles	An incident investigation was conducted. Valving wil be changed on the vehicle. Additional training will now be required for personnel operating this vehicle.
5889	12/13/2009	KIC	254	43% Seawater, 57% Fresh Water	A valve on a portable tank that was in prior seawater service was missing a plug and camlock fitting, allowing steam condensate and seawater to escape.	Tanks	Washbay check-in form will be modified to ensure missing or damaged equipment is well communicated, and new procedures to mitigate the risk of spills when cleaning damaged equipment will be developed and rolled-out.
6329	3/7/2010	2Z	105	60% Glycol, 40% Fresh Water	Following glycol transfer, hoses and pumps were drained and crew went to lunch. During lunch, inner butterfly valve malfunctioned and outer blowdown valve on hose was slightly cracked open, allowing glycol to flow out of tanker.	Tanks	Leaking butterfly valve was repaired.
6470	3/26/2010	1D	328	100% Crude Oil	Shallow casing leak. Diagnostic work indicates a potential leak at depth of 40 feet.	Wellhead/annulus releases	The well has been cemented and the cellar lined. The casing will now be repaired or the well will be plugged and abandoned.

TABLE C-1 (CONTINUED): KUPARUK SPILL HISTORY

Spill #	Date	Location	Volume (Gal)	Product	Cause Explanation	Source	Corrective Action
6710	4/17/2010	2T	189	100% Diesel	Forklift accidentally hit tree plug while attempting to remove floor kit from well. 185 gallons of diesel containing a traced of crude spilled into unsealed cellar area, and 4 gallons misted onto snow covered area behind well and over reserve pit.	Wellhead/annulus releases	Create well removal JHA to assist in evaluation of well trees and necessary clearances for removal. Any floor kits with lesss than 6" of clearance will require approval from ds lead prior to work. Modify tha card to include area dedicated specifically to removal of floor kits, with reminders to contact dso when tight clearance is an issue, clearing dirt/gravel away from well, etc.
6753	4/25/2010	3R	84	100% Produced Water	Pinhole leak caused by internal corrosion. Leak was discovered at 9:40 am. Flowline was shut in, depressured, and evacuated.	Pipe/flowlines/hardlines	Line will be replaced and the inspection frequency will be increased on 6" well lines. GKA is already pursuing the strategy to replace 6" well lines with 4" lines when warranted, increasing velocity and providing increased wall thickness.
6810	5/6/2010	CPF2	69	60% Glycol, 40% Fresh Water	Pump seal failure due to bad bearings	Pumps	Bearings and seals were repaired. Maintenance schedule was investigated and found to be adequate at every 6 months.
7029	5/31/2010	3N	110.5	100% Triethylene Glycol	Teg heater end cap flanges periodically leak with temperature swings. In this case, the heater was down due to the taps incident and just brought back up.	Flanges	The gasket on this line heater will be upgraded to prevent recurrence.
7226	6/20/2010	CPF1	200	100% Diesel	While running on diesel, generator G201B started leaking out of the fuel gas vent. It is theorized that a check valve internal to the purge block may have failed.	Compressor vents/module vents	The fuel valve was isolated. Operations will evaluate options for installing an alternate source of fuel gas, eliminating the check valve system.
7581	8/21/2010	1L	92	100% Diesel	Back-pressure of diesel from injection well sub-surface safety valve (SSSV) into hydraulic panel tubing caused spray release.	Fittings/seals/connections	Needle valve at tree used to immediately isolate hydraulic panel line. Leaking sssv will be repaired when slickline can access the well again.
7882	10/24/2010	2T	2,562.00	100% Brine	Outer annulus valve was left open and un-capped after completion of wellwork. It was also discovered that the sump alarm float was installed incorrectly and was being tested by manual trigger only. Outflow from the valve spilled to containment with approximately 3 barrels overflowing to gravel pad when wellwork resumed.	Valves	1) Nordic procedures, including the "cellar checklist" were revised to direct closing and capping/plugging of annular valves. 2) The manufacturer's instructions for cellar sump alarm installation are being reviewed with all crews. 3) A new method of testing cellar sump floats was developed that requires triggering the alarm with fluid to ensure float operates correctly. 4) The incident and findings are being shared with all nordic rigs through nordic's safety communication system.

TABLE C-1 (CONTINUED): KUPARUK SPILL HISTORY

Spill #	Date	Location	Volume (Gal)	Product	Cause Explanation	Source	Corrective Action
8444	12/17/2010	KIC	90	100% Diesel	A vac-truck pony motor leaked from the fuel filter seal. 87 gallons was contained in the motor compartment; 3 gallons spilled to ground. Upon investigation, the cause was determined to be a faulty fuel filter.	Fittings/seals/connections	The filter was changed and the vendor was notified.
8564	1/3/2011	1E	185	100% Diesel	Crew set up for a job on 1/1/11 and job was delayed due to a blow. When crew returned on 1/3/11 to start the job, they discovered that the pan on the pod blender was full of diesel soaked snow and and area next to the pan was also contaminated with diesel. Suspect that a plug on the end of an 8" drain line was loose.	Pipe/flowlines/hardlines	A procedure will be developed for leaving frac equipment on site and unattended. This procedure will address evacuating and isolating the piping, as well as define when and how equipment will be left unattended.
8643	1/9/2011	2L	1,890.00	100% Drilling Mud	The well took a "gas kick" while tripping out of the hole. The root cause investigation found the following: gas was entrained in the oil-based mud and moving up the well bore, but the rig drilling team wasn't aware of it. When the rig drilling team did see a very small amount of flow from the well, they decided they would circulate more mud into the well. The drilling team thought they would have time to react if flow from the well increased.	Wellhead/annulus releases	Immediately following the release, the well was shut in and mud was returned to the well bore, stabilizing the subsurface conditions. When drilling commenced, mud weight was increased. Following the investigation, preventive measures were assigned: 1) change the policy for coming off bottom to include requiring any differences between the mud fill volume and the trip sheet expected fill volume to be announced over the intercom for every stand that is removed, to ensure the full drilling team is aware of the conditions as they happen. 2) review the conocophillips well shut in requirements to ensure consistency with communications given to rig crews. Provide more clarity on what conditions require a well shut in. Communicate to all rigs the requirement that all crews review the conocophillips shut in policy at each hole section. 3) conduct a training on oil-based mud (OBM) properties to all rig team members with an emphasis on the fact that obm has a high gas solubility which will entrain gas liquids at shallow depths in the well bore, giving less time to react than expected.

TABLE C-1 (CONTINUED): KUPARUK SPILL HISTORY

Spill #	Date	Location	Volume (Gal)	Product	Cause Explanation	Source	Corrective Action
8731	1/14/2011	2L	588	100% Drilling Mud	The drilling mud transfer hose was not connected to the rig. Employees did not walk the hose and piping down as required in procedures. After opening the discharge valve, the truck driver saw the hose move out of the rig so shut down the transfer.	Transfer hoses	1) communicate fluid transfer requirements to all employees and consequences associated with non-compliance; 2) audit recent fluid transfer permits to determine completeness and effectiveness
9950	4/16/2011	KCC	300	100% Black Water	The pump in the main KCC sump malfunctioned. ~300 gals to gravel.	Sumps	
10230	5/13/2011	2H	110	100% Glycol	Hose failed resulting in glycol leaking into containment (100 gals) and some getting onto the pad (10 gals) at DS-2H pad.	Transfer hoses	1. In the future, crews will install hardline drains in the risers, and not the bottom drain of the tank. Roustabout foreman/N1060 17 May 2011 2.crews will no longer use camlocks on drain/downstream side roustabout foreman/N1060 17 May 2011 3.research and provide information on results to 624 superintendent regarding alternate tools to dog the camlock ears roustabout foreman/N1060 30 May 2011 4. Capture procedure changes / modifications in SOP. POA/N2129 30 Jun 2011 5. Audit two future projects for adherence to new sop. Audits to be conducted 1 each by foreman and 624 HSET specialist. Roustabout foreman/N1060 624 HSET specialist/N1672 01 Aug 2011
10270	5/18/2011	2G	124	89% Crude Oil, 10% Diesel, 1% Other	DS-2G well 11 released 124 gallons of arctic pack from the pressure safety valve. The arctic pack sprayed the inside of the well house and misted a light dusting to the snow outside the well house. (incident investigation underway)	Wellhead/annulus releases	TBD
11173	9/5/2011	CPF1	462	100% Diesel	TMS system entry was correct, however incorrect signal was sent to plc, causing incorrect valve line up. Driver did not verify correct valve line up prior to hitting 'start' button.	Tanks	

TABLE C-1 (CONTINUED): KUPARUK SPILL HISTORY

Spill #	Date	Location	Volume (Gal)	Product	Cause Explanation	Source	Corrective Action
11813	11/15/2011	KCS	300	100% Cortron RU-276	Tank overfill during a fluid transfer	Tanks	1. One discharge hose will be attached to each iso tank at the KCS tank farm. Each hose will be labeled at the end with a caution tag that identifies both the chemical and the tank number that the hose is being used for. 2. Update weekly inspection lists to include hose and label integrity checks for each tank, and then communicate to those employees who perform these inspections. 3. The signage on each ISO tank at the KCS tank farm will be updated to be more visible by making them larger and brighter. 4. Before test chemicals are purchased and ordered, communication must take place between the materials group and the chemical group to verify that the department has adequate assets to support all processes safely. The North Slope assets integrity operations supervisor will be contacted and this information will be discussed on a weekly basis at chemical group meetings. 5. Chemical group meetings will be audited by a materials group supervisor at a minimum of once a month for the next six months, to ensure that the materials group chemical transport and delivery equipment availability is compatible with any new chemical supply or upcoming chemical operations. 6. Create, review, complete, and communicate a job hazard analysis for all chemical transfer operations performed at KCS chemical tank farm. Include in the JHA a mandatory review of the north slope environmental field handbook (nsefh) fluid transfer guidelines as well as including these guidelines specifically as they pertain to each job step. 7. Update, review, complete, and communicate the existing jha for all chemical transfer operations performed at kuparuk drillsites, as above.

TABLE C-1 (CONTINUED): KUPARUK SPILL HISTORY

Spill #	Date	Location	Volume (Gal)	Product	Cause Explanation	Source	Corrective Action
11813 (continued)	11/15/2011	KCS	300	100% Cortron RU-276	Tank overfill during a fluid transfer	Tanks	8. Create, review, complete, and communicate a tha for chemical truck operators to use on a daily basis. Include all fluid transfer guidelines from the nsefh, focus on operations where a two person fluid transfer should be reviewed and sections designated for different types of fluids transfers, chemicals, locations, etc.
13719	4/21/2012	1J	710	100% Produced Water	Micromotion flow meter failure. Produced water used to power downhole jetpump spilled from the failed meter. CPF1 drill site maintenance employees were in the process of opening valves to allow produced water power fluid supplying the well 1J-137 downhole jet pump to be put back in service. During the process of opening these valves, there was a loss of containment from well house piping. The failure occurred on the inlet elbow of a 1-inch emerson micromotion mass flow meter.	Equipment failure. Corrosion in flow meter at well 1J-137	1. Ensure control system design and material specification addresses velocity limitations for Coriolis-type flow meters based on service. 2. Ensure that instrument design specifications assume that all produced water streams contain entrained solids. 3. Ensure that piping design specifications assume that all produced water streams contain entrained solids. 4. Provide additional guidance in piping design specifications for velocity reductions for entrained solids. 5. Establish a process to review all downhole changes for potential effects to surface facilities. 6. Determine maximum erosional velocities for all Coriolis-type mass flow meters currently in liquid service and set operating limits in SETCIM. 7. Modify moc process to ensure that all process safety analyses evaluate velocity/erosion issues. Consider a checklist based approach. 8. Perform NDE inspection of all micromotion mass flow meters that may see liquid with entrained solids service. This is complete for CPF1. 9. Shut in or modify all installations that are outside of manufacturer's recommendations and/or show excessive erosion through NDE inspections.

TABLE C-1 (CONTINUED): KUPARUK SPILL HISTORY

Spill #	Date	Location	Volume (Gal)	Product	Cause Explanation	Source	Corrective Action
14316	6/11/2012	Well 2T-202	504	100% Produced Water	The 2T-202 spill occurred due to a open bleeder on an instrument valve assembly. The spill occurred when the temporary well house shelter (heavy plastic sheeting typically used as valve blankets) tore due to 40+ mph winds. A section of the liner wrapped around the bleed valve and then partially opened the valve as the liner was pulled in a different direction by the circling winds between in place permanent well house shelters.		
14392	6/20/2012	CPF2	100	99% Fresh Water, 1% Hydrocarbon Mixture	Blockage in line. Line was not blown down adequately.	Stv suction scrubber inside facility	Operator error. Review procedures.
14756	7/20/2012	Mine site C; temporary hot oil plan operation	450	100% Diesel	Valve on third-party owned/operated diesel tank failed and spilled diesel into secondary containment.	Valve gasket failure.	Replaced all cork gaskets on valves with new Teflon gaskets.
15015	8/8/2012	Well 2G-11	90	100% Diesel	Replaced plug in conductor port.	Conductor seal under tree	Procedures adjusted based on incident investigation findings.

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TABLE C-2
KUPARUK SPILLS TO TUNDRA AND WATER

Date of Discharge	Discharge Cause; Spill Source	Material Discharged	Amt Discharged (gal)	Amt of Discharge that Reached Navigable Waters (gal)		Amt of discharge that Reached secondary Contain-ment (gal)	Cleanup Actions	Corrective Action	Enforce-ment Action?	Cause Explanation/ Description of Detection
				Tundra	Water					
Unknown	Cause: Unknown; Source: Not specified	Diesel - 100%	2	2	0	0	-	-	No	Personnel drilling VSM holes in tundra for Pioneer water injection line tie-in from DS 3H to DS 3A encountered historic contamination on 4/7/2007.
4/8/1986	Cause: Rolling Stock Leak; Source: Not specified	Arctic Diesel - 100%	700	700	0	0	100% Recovered; Disposal Location DS-1C Pit	Hard pipe will be used as "filling line" instead of rubber hose. Better positioning and insulation for the hose will be utilized.	No	Hammer lock clamps on diesel line burst(int of 3n & Oliktok)
7/5/1986	Cause: Human Error; Source: Not specified	Crude-50%; Diesel-50%	40	40	0	0	100% Recovered; Disposal Location NSB Incinerator	Re-evaluate snow removal process.	No	Contaminated snow pushed onto tundra by snow removal crews.
7/9/1986	Cause: Human Error; Source: Not specified	Crude-100%	5	5	0	0	-	None.	No	Drain barrel pushed onto tundra with snow during snow removal
7/9/1986	Cause: Human Error; Source: Not specified	Crude-100%	5	5	0	0	-	Hauled contaminated snow or gravel to disposal site immediately after clean up.	No	Contaminated snow or gravel pushed off pad during snow removal
7/20/1986	Cause: Other Cause; Source: Not specified	Thread Dope-100%	0.3	0.3	0	0	-	Caution rig crews concerning house keeping on locations.	No	Shen from thread dope on the protectors
8/30/1986	Cause: Flange Leak/Failure; Source: Not specified	Produced Water-100%	280	280	0	0	Disposal Location CPF-1 (Oily Waste)	None.	No	Flange leak in 10" produced water line.
3/13/1987	Cause: Rolling Stock Leak; Source: Not specified	Glycol-50%; Produced water-50%	3	0	3	0	KCS snowmelt	Inspect all hoses regularly	No	Broken radiator hose on water truck on cpf2 lake

TABLE C-2 (CONTINUED):
KUPARUK SPILLS TO TUNDRA AND WATER

Date of Discharge	Discharge Cause; Spill Source	Material Discharged	Amt Discharged (gal)	Amt of Discharge that Reached Navigable Waters (gal)		Amt of discharge that Reached secondary Contain-ment (gal)	Cleanup Actions	Corrective Action	Enforce-ment Action?	Cause Explanation/ Description of Detection
				Tundra	Water					
7/18/1987	Cause: Element Aided; Source: Not specified	Fuel-100%	3	3	0	0	-	Keep Fuel level lower	No	Minor amount of fuel on top of water adjacent to training grounds
7/19/1987	Cause: Other Cause; Source: Not specified	Crude-100%	2	1	1	0	-	All employees received training in spill prevention.	No	Old spill of crude on tundra - gravel was spread over. Cause is unknown.
8/18/1987	Cause: Rolling Stock Leak; Source: Not specified	Crude-20%; Diesel-80%	2	2	0	0	-	Installing safety chains on trailer to attach to truck.	No	Bleed tank being hauled by trailer turned over & spilled contents.
9/19/1987	Cause: Valve Leak/Failure; Source: Not specified	Crude-100%	84	84	0	0	Disposal Location NSB Incinerator	Continued observation of cross-country flow lines.	No	Slow leak at 24" valve in line 24".
11/8/1987	Cause: Rolling Stock Leak; Source: Not specified	Diesel - 100%	500	500	0	0	Disposal Location NSB Incinerator	None.	No	Broken drive line hit fuel line under truck.
5/11/1988	Cause: Corrosion/ Erosion; Source: Not specified	Diesel - 100%	10	10	0	0	-	Be aware of valves during startup.	No	BLED & PURGING NEW GAS INJECTION LINE FROM JUNCTION OF 2U-2W PAD.
2/13/1989	Cause: Rolling Stock Leak; Source: Not specified	Hydraulic Fluid - 100%	5	5	0	0		Manufacture defect.	No	Hydraulic hose parted on 22-4 snowblower. On 2w ice road.
3/8/1989	Cause: Human Error; Source: Not specified	Hydraulic Fluid - 100%	1	1	0	0	-	Drain pans will be available to catch leaks at the site of any similar incidents.	No	Hydraulic line damaged during towing of gravel truck back on to road.
6/23/1989	Cause: Other Cause; Source: Not specified	Crude-100%	1	1	0	0		Snow disposal restrictions are in place. Employees have been instructed to inspect work areas for spills and cleanup immediately.	No	Contaminated snow was apparently pushed off pad during past winter

TABLE C-2 (CONTINUED):
KUPARUK SPILLS TO TUNDRA AND WATER

Date of Discharge	Discharge Cause; Spill Source	Material Discharged	Amt Discharged (gal)	Amt of Discharge that Reached Navigable Waters (gal)		Amt of discharge that Reached secondary Contain-ment (gal)	Cleanup Actions	Corrective Action	Enforce-ment Action?	Cause Explanation/ Description of Detection
				Tundra	Water					
6/28/1989	Cause: Other Cause; Source: Not specified	Frac Gel - 100%	10	10	0	0	Disposal Location : CPF1 Oily Waste	Stressed importance of careful examination of work area after activities occur.	No	Suspect contaminated snow from well workover pushed off pad.
6/29/1989	Cause: Temperature Related; Source: Not specified	Crude-33%; Diesel-33%; Produced Water-34%	42	0	42	0	Disposal Location: CPF1 Oily Waste and DS-1H Pit	Suspected pipeline to be inspected and causes evaluated to determine cause prevention measures.	No	Suspect former produced water line suffered freeze damage and leaked.
7/2/1989	Cause: Rolling Stock Leak; Source: Not specified	Snow Melt Water - 100%	8400	8400	0	0	-	Tanker hitches will be checked periodically and repaired as necessary.	No	Bumper on tanker broke dislodging fittings between tanker trailers.
7/5/1989	Cause: Weld Failure; Source: Not specified	Diesel - 100%	420	0	420	0	Disposal Location: DS-1H Pit	None.	No	Weld failed on coiled tubing unit
8/8/1989	Cause: Human Error; Source: Not specified	Diesel - 100%	2	2	0	0	Disposal Location: NSB Incinerator	Supervisor notified to maintain closer observation and control of loader operator.	No	Loader left road and upset on soft shoulder of road spilling diesel.
8/25/1989	Cause: Corrosion/ Erosion; Source: Not specified	Crude - 85%; Produced Water - 15%	25200	25200	0	0	Disposal Locations: CPF1 Oily Waste; DS-1H Pit; NSB Incinerator	Replaced valve and addressing cause of valve component failure. Continue pipeline surveillance. Keep boom in place into next summer.	Yes	Valve component failed and allowed crude to leak from valve assembly
9/4/1989	Cause: Valve Leak/Failure; Source: Not specified	Crude - 100%	0.1	0	0.1	0	Disposal Location: NSB Incinerator	Serviced valve to stop leaking.	No	Valve stem packing on 2-a pipeline tie-in valve leaked.
10/3/1989	Cause: Valve Leak/Failure; Source: Not specified	Crude - 100%	0.3			0	Disposal Location: NSB Incinerator	Upstream valve closed against flange and flange tightened.	No	Loose blind flange on ball valve leaked.
11/4/1989	Cause: Human Error; Source: Not specified	Diesel - 100%	5	5	0	0	Disposal Location: NSB Incinerator	Drivers instructed to use turnaround area at cpf-1 rather than attempt to	No	Driver didn't complete turn. Truck slid off road & fuel tank ruptured.

TABLE C-2 (CONTINUED):
KUPARUK SPILLS TO TUNDRA AND WATER

Date of Discharge	Discharge Cause; Spill Source	Material Discharged	Amt Discharged (gal)	Amt of Discharge that Reached Navigable Waters (gal)		Amt of discharge that Reached secondary Contain-ment (gal)	Cleanup Actions	Corrective Action	Enforce-ment Action?	Cause Explanation/ Description of Detection
				Tundra	Water					
								negotiate the turn on icy road.		
12/17/1989	Cause: Other Cause; Source: Not specified	Crude-100%	0.5	0.5	0	0	Disposal Location: NSB Incinerator	Inspected all remaining equipment and pplace sorbent booms in fromt of all flush lines.	No	Fluid found floating on fresh water during major cleanup
1/2/1990	Cause: Corrosion/ Erosion; Source: Not specified	Crude-50%; Diesel-50%	15	4		0	Disposal Location: CPF1 Oily Waste	Redesign choke size and piping for certain applications.	No	During cleanout of well #4 temporary choke eroded, mist cloud formed
3/4/1990	Cause: Valve Leak/Failure; Source: Not specified	Crude-100%	25	25	0	0	Disposal Location: NSB Incinerator	Leak was detected during scheduled preventive maintenance check. Valve was greased and checked per preventive maintenance schedule.	No	Valve stem packing on 2a pipline tie-in valve leaked.
3/16/1990	Cause: Rolling Stock Leak; Source: Not specified	Diesel - 60%; Hydraulic Fliud - 40%	5	5	0	0	Disposal Location: CPF1 Oily Waste	Verify brakes before releasing vehicle.	No	Wireline unit brakes froze. Unit overturned on side of road near pad.
3/29/1990	Cause: Other Cause; Source: Not specified	Crude - 100%	10	10	0	0	Disposal Location: CPF1 Oily Waste	Keep well choked back.	No	Carried over crude during test beyond flare pit.
4/16/1990	Cause: Rolling Stock Leak; Source: Not specified	Motor Oil - 100%	<1oz	0	<1oz	0	Disposal Location: NSB Incinerator	Replace with other generator.	No	Dripping detected on portable generator on ice. Less than ounce spill
5/1/1990	Cause: Temperature Related; Source: Not specified	Crude-50%; Produced Water-50%	25	25	0	0	Disposal Location: 2Z Recycle	Monitor tank temperatures to ensure compatible with incoming fluids.	No	Tank temperature caused vaporization and carry over from tank vent.
5/20/1990	Cause: Rolling Stock Leak; Source: Not specified	Diesel-100%	50			0	Disposal Locations: NSB Incinerator; 2Z Recycle	Fueling procedures being reviewed.	No	Suspect vehicle fueling practices.

TABLE C-2 (CONTINUED): KUPARUK SPILLS TO TUNDRA AND WATER

Date of Discharge	Discharge Cause; Spill Source	Material Discharged	Amt Discharged (gal)	Amt of Discharge that Reached Navigable Waters (gal)		Amt of discharge that Reached secondary Contain-ment (gal)	Cleanup Actions	Corrective Action	Enforce-ment Action?	Cause Explanation/ Description of Detection
				Tundra	Water					
7/10/1990	Cause: Rolling Stock Leak; Source: Not specified	Gasoline-100%	<1	0	<1	0	-	Be more cautious in driving and stopping the boat.	No	Air boat swamped during oil spill training exercise. 1/2 cup of gas came out of fuel tank.
12/22/1990	Cause: Threaded Connection; Source: Not specified	Hydraulic Fluid - 100%	<1			0	Disposal Location: NSB Incinerator	O-ring was replaced.	No	O-ring failed causing spray of hydraulic fluid.
1/16/1991	Cause: Element Aided; Source: Not specified	Crude-50%; Diesel-50%	2	1	0	0	Disposal Location: 2Z Recycle	Review sop for unloading with operator	No	Top hatch on tank left open. While unloading into tank some mist sprayed out of hatch and carried over snow.
2/24/1991	Cause: Lubricator Failure; Source: Not specified	Crude-90%; Diesek-10%	10	2	0	0	Disposal Location: CPF1 Oily Waste	-	No	O-ring seat expired during initial pressure test of surface equipment
3/1/1991	Cause: Lubricator Failure; Source: Not specified	Lubricator Tool Grease-100%	0.3	0.1	0	0	Disposal Locations: CPF1 Oily Waste; 2Z Recycle	-	No	Lubricator cooling tubes clogged or froze up causing pressure to build up behind lubricator packing and grease leaked to ambient environment. Wind carried grease drops onto pad and snow.
5/26/1991	Cause: Rolling Stock Leak; Source: Not specified	Diesel-100%	0.5	0	0.5	0	Disposal Location: CPF1 Oily Waste; NSB Incinerator	Driver instructed to avoid soft shoulders.	No	Driver pulled trailer off edge of road and trailer turned over
6/30/1991	Cause: Rolling Stock Leak; Source: Not specified	Crude-100%	0.5	0.5	0	0	Disposal Location: NSB Incinerator	Will discuss at safety meetings importance of adhering to all operating procedures to prevent reoccurrence of such spills.	No	Suspect mobile tanker discharge.
7/8/1991	Cause: Human	Reserve Pit	0.5	0.5	0	0	Disposal Location: CPF1	Drivers cautioned to maintain	No	Water tanker turned curve

TABLE C-2 (CONTINUED): KUPARUK SPILLS TO TUNDRA AND WATER

Date of Discharge	Discharge Cause; Spill Source	Material Discharged	Amt Discharged (gal)	Amt of Discharge that Reached Navigable Waters (gal)		Amt of discharge that Reached secondary Contain-ment (gal)	Cleanup Actions	Corrective Action	Enforce-ment Action?	Cause Explanation/ Description of Detection
				Tundra	Water					
	Error; Source: Not specified	Water-100%					Oily Waste	distance from edge of road.		too close, tank broke off lowboy and spilled water.
7/9/1991	Cause: Other Cause; Source: Not specified	Crude-100%	5	5	0	0	90% Recovered; Disposal Locations: DS-1H Pit, 2Z Recycle	-	No	Unknown, suspect vac truck operator used a contaminated hose during fluid recovery
8/10/1991	Cause: Other Cause; Source: Not specified	Diesel-100%	0	0		0	100% Recovered; Disposal Location:NSB Incinerator	Skimmers will be throughly cleaned after use.	No	Residual diesel on disc skimmer caused a sheen during deployment.
1/13/1992	Cause: Hose Failure; Source: Not specified	Hydraulic Fluid - 100%	2	0	2	0	100% Recovered; Disposal Location:NSB Incinerator	Possible restriction of use during extreme cold.	No	Hydraulic hose ruptured.
1/28/1992	Cause: Rolling Stock Leak; Source: Not specified	Hydraulic Fluid - 100%	0.3	0.3	0	0	100% Recovered; Disposal Location:NSB Incinerator	Preventative maintance and use drip pans.	No	Unknown.
2/25/1992	Cause: Rolling Stock Leak; Source: Not specified	Hydraulic Fluid - 100%	20	25	0	0	100% Recovered; Disposal Location:NSB Incinerator	Pre-heat the oil.	No	Hydraulic filter blew off.
3/1/1992	Cause: Valve Leak/Failure; Source: Not specified	Crude-100%	<1		0	0	100% Recovered; Disposal Location:CPF1 Oily Waste	Tightened packing on the valve.	No	Tee block valve leaked on production line jumper.
3/28/1992	Cause: Human Error; Source: Not specified	Crude-100%	15	15	0	0	100% Recovered; Disposal Location:Milne Point	Have tanks clean and piping blinded off prior to moving.	No	Well test equipment was being transported to Cirque well. Crude leakeed from piping and inspection ports on truck.
3/28/1992	Cause: Rolling Stock Leak; Source: Not specified	Hydraulic Fluid - 100%	0.5	0.5	0	0	100% Recovered; Disposal Location:CPF1 Oily Waste, NSB Incinerator	Use Absorbent Pads.	No	Hydraulic ram seal on crane leaked.
5/30/1992	Cause: Other Cause; Source: Not	Unknown-100%	5	5	0	0	100% Recovered; Disposal Location:DS-1H Pit and	-	No	Unkown, spill found by security.

TABLE C-2 (CONTINUED):
KUPARUK SPILLS TO TUNDRA AND WATER

Date of Discharge	Discharge Cause; Spill Source	Material Discharged	Amt Discharged (gal)	Amt of Discharge that Reached Navigable Waters (gal)		Amt of discharge that Reached secondary Contain-ment (gal)	Cleanup Actions	Corrective Action	Enforce-ment Action?	Cause Explanation/ Description of Detection
				Tundra	Water					
	specified						NSB Incinerator			
6/5/1992	Cause: Other Cause; Source: Not specified	Motor Oil - 100%	0.5	0.5	0	0	100% Recovered; Disposal Location:NSB Incinerator	Continue to educate personnel on awareness and to be pro-active on spill prevention.	No	Unknown.
6/8/1992	Cause: Other Cause; Source: Not specified	Diesel-100%	3	3	0	0	100% Recovered; Disposal Location:2Z Recycle, CPF3 Drip Tank	N/A cause is unknown.	No	Unknown Cause.
6/15/1992	Cause: Other Cause; Source: Not specified	Motor Oil - 100%	3	2	0	0	95% Recovered; Disposal Location:NSB Incinerator	N/A cause is unkown.	No	Unknown. Suspect material leaked when Potable water truck overturned in that area this winter.
6/19/1992	Cause: Other Cause; Source: Not specified	Lubricating grease-100%	0.5	0.5	0	0	100% Recovered; Disposal Location:NSB Incinerator	Spoke with contractor and vendors about maintaining clean conditions.	No	Unknown, found after snow melted from area.
6/20/1992	Cause: Human Error; Source: Not specified	Drill cuttings and Polymer-100%	336	336	0	0	100% Recovered; Disposal Location:DS2X Disposal Well	In the future , piled drill cuttings will be stored away from the edge of the pad prior to processing.	No	Drill cuttings were unknowingly plowed off the side of the pad from the staging area this winter.
6/28/1992	Cause: Rolling Stock Leak; Source: Not specified	Diesel-100%	5	0	5	0	100% Recovered; Disposal Location:NSB Incinerator, 2Z Recycle	Continue orientation for new employees, montior by Peak safety/foreman.	No	Gravel berm on side of perimeter road gave way below dewater truck, causing it to overturn off pad.
7/19/1992	Cause: Human Error; Source: Not specified	Diesel-100%	2	2	0	0	100% Recovered	Counsel operators on driving near shoulders with long loads.	No	Watertruck was too close to soft shoulder and went over the side onto the tundra.
8/24/1992	Cause: Flange Leak/Failure; Source: Not specified	Crude-100%	0.1	0.1	0	0	100% Recovered; Disposal Location:NSB Incinerator	-	No	Crude leaked from a flange into the valve box, then onto tundra.
9/3/1992	Cause: Rolling Stock Leak;	Diesel-100%	2	2	0	0	99% Recovered; Disposal	All employees were instructed not to get too close	No	Road compactor was compacting DS2M a/r

TABLE C-2 (CONTINUED): KUPARUK SPILLS TO TUNDRA AND WATER

Date of Discharge	Discharge Cause; Spill Source	Material Discharged	Amt Discharged (gal)	Amt of Discharge that Reached Navigable Waters (gal)		Amt of discharge that Reached secondary Contain-ment (gal)	Cleanup Actions	Corrective Action	Enforce-ment Action?	Cause Explanation/ Description of Detection
				Tundra	Water					
	Source: Not specified						Location:NSB Incinerator	to the edge of the road while operating heavy equipment		when it fell off the shoulder of the road, rolled on its side and leaked some fuel from fuel tank.
9/17/1992	Cause: Human Error; Source: Not specified	Diesel-100%	336	336	0	0	100% Recovered; Disposal Location:2Z Recycle	Under investigation.	No	While doing Hydro test on gas lift line, fitting at manifold building was not tightened.
1/17/1993	Cause: Pressure Related; Source: Not specified	Drill Mud-100%	84	84	0	0	10% Rig Mud System	Hold circulation to slower rate to be sure liquid is not vented with gas.	No	Pressure kick caused gas to vent with mud entrained.
3/22/1993	Cause: Temperature Related; Source: Not specified	Drill Mud-100%	1470	966	0	0	99% Recovered; Disposal Location:3R Ball Mill	The Ball Mill has been modified to pump non-frozen drilling muds directly into the Ball Mill. Future ice containment areas will be built with thicker walls.	No	An ice containment area melted discharging muds/cuttings to the gravel pad and off the edge of the pad.
9/2/1993	Cause: Corrosion/ Erosion; Source: Not specified	Crude-54%; Produced Water-46%	4620	4620	0	0	100% Recovered; Disposal Locations:NSB Incinerator, 2Z Recycle	Under investigation.	No	Corrosion leak in 18" PO line.
9/20/1993	Cause: Human Error; Source: Not specified	Crude-10%; Diesel-90%	336	168	0	0	100% Recovered; Disposal Locations:DS-1H, 2Z Recycle	Discussed with employee the importance of rechecking all aspects on a system when a change has been made to any part of that system.	No	Bleed tank overfilled during freeze protection preperations of Divert tank to/from line.
7/23/1994	Cause: Hose Failure; Source: Not specified	Gasoline-100%	0.3	0	0.3	0	100% Recovered; Disposal Location: NSB Incinerator	Fuel line repaired.	No	Broken fuel line on outboard engine.
7/26/1994	Cause: Valve Leak/Failure; Source: Not specified	Crude-100%	0.1	0.1	0	0	100% Recovered; Disposal Location: NSB Incinerator	Replaced lock open feature on valve with a cap.	No	packing leak on flow line check valve

TABLE C-2 (CONTINUED): KUPARUK SPILLS TO TUNDRA AND WATER

Date of Discharge	Discharge Cause; Spill Source	Material Discharged	Amt Discharged (gal)	Amt of Discharge that Reached Navigable Waters (gal)		Amt of discharge that Reached secondary Contain-ment (gal)	Cleanup Actions	Corrective Action	Enforce-ment Action?	Cause Explanation/ Description of Detection
				Tundra	Water					
10/31/1994	Cause: Corrosion/ Erosion; Source: Not specified	Crude-30%; Produced Water-70%	23100	23100	0	0	95% Recovered; Disposal Location: CPF1 Oily Waste, NSB Incinerator, 2Z Recycle	Field wide corrosion inhibition program spending has increased from $9.5 million in 94 to $15 million in 95. Corrosion surveillance inspection has been increased in susceptible areas.	No	Crack in flowline.
1/7/1995	Cause: Valve Leak/Failure; Source: Not specified	Crude-85%; Produced Water-15%	252	252	0	0	100% Recovered; Disposal Location: NSB Incinerator, 2Z Recycle	A cap for the swing arm was made and installed in place of the leaking bushing. Continue tundra valve PMs, monitoring pipelines and valves away from main drill sites.	No	Bushing on external swing arm of an 12" check valve on main production line from drill site 3M to 3I failed allowing crude oil, gas and produced water to leak out of the line and onto the snow which covers the 3M drill site and tundra.
5/28/1995	Cause: Rolling Stock Leak; Source: Not specified	Diesel-50%, Hydraulic Fluid-50%	0.3	0	0.3	0	Disposal Location: OW Dumpster	More extensive use of drip pans and absorb should be installed under temporarily parked mobile equipment to catch minor leaks.	No	Sheen on top of snow meltwater. Suspected cause is misc. vehicle leaks during pipeline construction.
5/28/1995	Cause: Rolling Stock Leak; Source: Not specified	Hydraulic Fluid - 100%	0.3	0	0.3	0	-	More extensive use of drip pans and absorb should be installed under temporarily parked mobile equipment to catch minor leaks.	No	Sheen was discovered on puddle next to pipelines. It is suspected that spill occurred during winter pipeline construction.
6/27/1995	Cause: Human Error; Source: Not specified	Hydraulic Fluid - 100%	0.3	0.3	0	0	100% Recovered	Instructed employees to pay attention to duties at hand. If necessary, stop and take a moment to gather thoughts and actions.	No	Mechanic as distracted and drove off 1H access road, causing truck to tip over on right side. Power steering fluid leaked from reservoir.
8/1/1995	Cause: Human Error; Source: Not specified	Crude-50%; Hydraulic Fluid-50%	0.5	0.5	0	0	100% Recovered; Disposal Location: NSB	Inform everyone to secure loads no matter how small. Also make sure to completely drain and clean drip containers.	No	A drip bucket used to catch small leaks or fluid being bled off of equipment or process fluids apparently blew out

TABLE C-2 (CONTINUED): KUPARUK SPILLS TO TUNDRA AND WATER

Date of Discharge	Discharge Cause; Spill Source	Material Discharged	Amt Discharged (gal)	Amt of Discharge that Reached Navigable Waters (gal)		Amt of discharge that Reached secondary Contain-ment (gal)	Cleanup Actions	Corrective Action	Enforce-ment Action?	Cause Explanation/ Description of Detection
				Tundra	Water					
										of the back of someone's truck. Actual source or party is unknown.
6/2/1996	Cause: Hose Failure; Source: Not specified	Hydraulic Fluid - 100%	0.2	0.2	0	0	100% Recovered; Disposal Location: CPF1 Oily Waste, DS-1H Pit	Emphasize need to report all spills immediately.	No	Unknown cause; probably carryover from road drips.
6/14/1996	Cause: Other Cause; Source: Not specified	Crude-100%	0.5	0.5	0	0	100% Recovered	More frequent inspections on pad, especially during construction and well work activities.	No	Probable carryover from snow removal on pad. Construction activity and drilling/workover on pad during winter.
6/17/1996	Cause: Hose Failure; Source: Not specified	Hydraulic Fluid - 100%	48	0.1	0	1	100% Recovered; Disposal Location: CPF1 Oily Waste, DS-1H Pit	Hydraulic hose inpection during PMs.	No	Broken hydraulic hose in center of mobile crane.
9/3/1996	Cause: Valve Leak/Failure; Source: Not specified	Crude-100%	0.1	0.1	0	0	100% Recovered; Disposal Location: CPF1 Oily Waste	Valve sealed with epoxy.	No	Valve back-plate gasket leak.
3/12/1997	Cause: Element Aided; Source: Not specified	Crude-50%; Diesel-50%	2	0.1	0	0	100% Recovered; Disposal Location: Hydrocarbon Recycle	More care/monitoring when flowing well into open top tank.	No	While flowing well into open top tank, fluid misted out.
4/30/1997	Cause: Other Cause; Source: Not specified	Crude-1%; Produced Water-99%	1732	1732	0	0	100% Recovered; Disposal Location: NSB Incinerator, Hydro/Water Recycle	The flare MSD line has been removed from service and blinded.	No	The freeze protect heat trace failed, resulting in the line being damaged by the frozen liquid.
5/3/1997	Cause: Other Cause; Source: Not specified	Crude-100%	98	1	0	0	Disposal Location: CPF1 Oily Waste, DS-1H Pit	Obstruction in bridle was cleared. FWR to modify bridle was included in June shutdown work.	No	Source of spill was the flare knockout. CPF-3 wet oil line PSV's lifted at set point and relieved to the flare knockout which carried over to the flare line and liquids were carried over the flare pits. 48 gallons was discharged into the west pit and 50

TABLE C-2 (CONTINUED): KUPARUK SPILLS TO TUNDRA AND WATER

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				Tundra	Water					gallons into the east pit.
5/20/1997	Cause: Human Error; Source: Not specified	Cuttings-100%	1	1	0	0	100% Recovered; Disposal Location: DS-1H Pit	Leave snow in pit and vacuum out as it melts.	No	While trying to move clean snow out of 1H Pit, contaminated solids were picked up and blown out with snow blower.
6/10/1997	Cause: Human Error; Source: Not specified	Oily Waste-100%	2	2	0	0	100% Recovered; Disposal Location: CPF1 Oily Waste, DS-1H Pit	Moved dumpsters into lined containment area.	No	Leaking dumpster.
7/15/1997	Cause: Corrosion/ Erosion; Source: Not specified	Crude-35%; Produced Water-65%	2000	500	1500	0	100% Recovered; Disposal Location: NSB Incinerator, 2Z Recycle	Prior to restart of the line, the balance of the weld pack insulated areas were inspected. Wet ones or suspect ones had the insulation stripped and the pipe visually and electronically inspected.	No	External corrosion under insulation at weldpack.
8/23/1997	Cause: Rolling Stock Leak; Source: Not specified	Hydraulic Fluid - 100%	0.1	0.1	0	0	100% Recovered; Disposal Location: Oily Waste Dumpster	Increased awareness is necessary to identify and repair any vehicle/equipment leaks.	No	Source of spill unknown, although it appears to be caused by drips from a pickup or mobile equipment.
9/15/1997	Cause: Corrosion/ Erosion; Source: Not specified	Crude-66%; Produced Water-34%	6	6	0	0	100% Recovered; Disposal Location: NSB Incinerator	Leak found during corrosion inspections of pipelines. ARCO Kuparuk has an external corrosion program and is currently conducting an extensive fieldwide weld pack survey that targets cross country lines carrying oil, produced water and gas. Areas of the field have been prioritized as well as priority inspections of weld packs in saddles. The program is scheduled through 1999.	No	External corrosion on production line at VSM saddle 483A.
11/16/1997	Cause: Corrosion/ Erosion;	Crude-1%; Produced Water-99%	3030	3030	0	0	100% Recovered; Disposal Location: NSB Incinerator, CPF-1 Water Recycle	New section of pipe installed with new heat trace/insulation. The line's	No	XXS e bow upstream of different thickness than piping and rest of elbows,

TABLE C-2 (CONTINUED): KUPARUK SPILLS TO TUNDRA AND WATER

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				Tundra	Water					
	Source: Not specified							elbows will be inspected to monitor for further problems. Limit to reduced pumping rates as frequently as possible.		causing increased velocity through the elbow and a washout of the downstream piping.
2/20/1998	Cause: Human Error; Source: Not specified	Diesel-100%	0.3	0.3	0	0	100% Recovered; Recycled for wellwork	Limit driving in adverse weather conditions. Stress need to stop vehicle if vision is seriously impaired.	No	Tractor/trailer left the road, falling onto its side.
5/12/1998	Cause: Other Cause; Source: Not specified	Crude-5%; Diesel-5%; Fresh Water-90%	1	1	0	0	100% Recovered	Hay bales and absorbent rolls placed around low drainage areas. Monitor area more frequently.	No	Snow melt drainage from gravel pad to tundra.
5/13/1998	Cause: Rolling Stock Leak; Source: Not specified	Diesel-100%	1	0.5	0.5	0	100% Recovered; Disposal Location: DS-1H Pit, CPF-1 Water Recycle, Oily waste dumpster	Increased surveillance frequency of vehicle parking lots during breakup.	No	Exact cause unknown. Most likely cause a diesel leak from a vehicle at the bullrail or leaking during fueling.
5/30/1998	Cause: Transformer bleed valve; packing failure; Source: Not specified	Mineral Oil-100%	5	3	0	2	100% Recovered; Disposal Location: Oily waste dumpster	Valves will be repaired.	No	Transformer bleed valve; packing failure.
11/23/1998	Cause: Human Error; Source: Not specified	Motor Oil - 100%	0.1	0	0.1	0	100% Recovered; Disposal Location: CPF-1 Hydrocarbon Recycle	Caution operators to avoid driving loaders onto ice. Test drill ice before running equipment on it.	No	Loader was clearing snow away from pump building at D-Pit when the ice gave way, causing loader to fall through. Small amount of lube oil leaked from loader.
1/4/1999	Cause: Equipment Difficulty; Source: Tanks	Crude-100%	1.1	0.8	0	0	100% Recovered; Disposal Location: CPF-1 Hydrocarbon Recycle	Secure demister properly.	No	Demister wasn't properly secured. Allowed mist to vent out of tank while flowing fluids into tank.
2/21/1999	Cause: Rolling Stock Leak; Source: Not	Diesel-100%	1	0	1	0	100% Recovered; Disposal Location: Snowmelter at	Fuel truck taked to F-Pit shop for repair.	No	Fuel line broke releasing fuel onto lake during

TABLE C-2 (CONTINUED): KUPARUK SPILLS TO TUNDRA AND WATER

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				Tundra	Water					
	Specified						B70 Pad			fueling operation.
7/9/1999	Cause: Equipment Difficulty; Source: Flanges	Electrical Transformer Oil-100%	42	20	0	0	Samples taken to lab to determine disposal options.	Energy isolated transformer and tightened bushing.	No	34.5kva transformer 'B' Phase bushing leaked.
7/10/1999	Cause: Equipment Difficulty; Source: Fittings/Seals/	Electrical Transformer Oil-100%	69	69	0	0	Waiting on lab results to determine disposal options.	Shut down transformer and damage assessment in progress by Electricians. Notice sent out to all area Supervisors to inspect for spills under all other transformers located throughout the field.	No	The insulator connection going into the transformer was broken and cracked allowing the internal oil to leak out.
7/23/1999	Cause: Corrosion/ Erosion; Source: Pipe/Flowlines / Hardlines	Crude-1%; Produced Water-99%	6300	3150	3150	0	23% Recovered; Disposal Locations: DS-1H Pit, CPF-1 Hydrocarbon Recycle, Other	To be determined.	No	The damage to the produced water line was caused by external corrosion at a weld pack in a saddle.
9/20/1999	Cause: Equipment Difficulty; Source: Fittings/Seals/ Connections	Crude-100%	1	1	0	0	100% Recovered; Disposal Location: DS-1H Pit	A new fitting cap was installed.	No	A plug fitting cap had a slow dripping leak.
9/27/1999	Cause: Procedures; Source: Pipe/Flowlines / Hardlines	Crude-20%; Produced Water-80%	3	1.5	1.5	0	100% Recoverd; Disposal Location: CPF-1 Water Recycle; Oily sorbents went to the oily waste dumpsters	Review procedures to prevent similar incident happening again.	No	While attempting to purge the line for welding, produced water burped from a low point to the opening in the line. Approximately 1.5 gallons went into secondary containment that was set up.

TABLE C-2 (CONTINUED):
KUPARUK SPILLS TO TUNDRA AND WATER

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				Tundra	Water					
7/3/2000	Cause: Unknown; Source: unknown	Treatolite Xcide-100%	25		0	0	95% Recovered; DS-1H Pit, CPF-1 Water Recycle	The area suspected to be the source is a subsurface box which produced water lines come down into and out of eventually running through culverts under the road and out to the tundra. Once secondary containment was put up around the colverts the level of glutaraldehide in the pond went from 80 ppm to non-detect. Once we removed gravel from the box area the fluids in the containment area went from 100 ppm to non-detect for glutaraldehide. Fluid in the box which started at 170 ppm glutaraldehide went down to 20 ppm after we removed the gravel. In removing the gravel an oily stain was discovered which is thought to be the original spill causing the high levels of glutaraldehide. The Pond, containment area and box will continue to be monitored.	No	A sheen was discovered coming out of the culverts at CPF1, south side of the sand jet slurry tank. The material was determined to contain Treatolite Xcide 0105.

TABLE C-2 (CONTINUED):
KUPARUK SPILLS TO TUNDRA AND WATER

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				Tundra	Water					
7/12/2000	Cause: Equipment Difficulty; Source: Fittings/Seals/ Connections	Produced Water-100%	424.2	5	0	0	100% Recovered; Disposal Locations: CPF1 Oily Waste and DS-1H Pit	Removed temporary choke spool and replaced with permanent spool. The failed components of the valve have been collected and will be forwarded tp Phillips-Bartesville for failure analysis.	No	Inside the pig launcher/receiver building a multi-port gauge valve failed. The bonnet and valve handle assembly had parted from the body of the guage valve. The multi-port gauge valve (MPGV) was a welded component of a temporary choke pipe spool used for filling the DS-2N MI pipeline with water for temporary water injection during summer months.
8/17/2000	Cause: Unknown; Source: unknown	Pole Treating Oil-100%	11	11	0	0	-	-	No	Coating from pressure treated power poles was discovered seeping into gravel and water adjacent to the poles. Poles are douglas fir treated with pentachlorophenol and pole treating oil. Volume estimate is based on estimate of approx. 1/2 cup at each location.
11/15/2000	Cause: Procedures; Source: Fittings/Seals/ Connections	Crude-100%	2	2	0	0	100% Recovered; Disposal Location: CPF-1 Hydrocarbon Recycle	Educate employees on valve body bleeders and the potential hazards associated with their use. Reinforce tagging and flagging procedures for valves left in certain positions.	No	Sprayed from valve body bleed plug when the tie-in valve was opened slightly.

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				Tundra	Water					
11/27/2000	Cause: Human Engineering; Source: Fittings/Seals/ Connections	Diesel-100%	0.3	0.3	0	0	100% Recovered; Disposal Location: CPF-1 Water Recycle; Small amout of diesel and snow was bagged and sent to the Kuparuk Spill Response Center where it was melted. Sorbents were used to collect the diesel, and the water was placed into a collection sump which will ultimately go to the Enhanced Oil Recovery Water Recycle Facility. The sorbents will be handled as oily waste.	Causal factors were determined to be darkness, time of day (gas cap was filled at 1am), and weather. Preventative measure is to increase spill awareness.	No	Fuel cap on a Tucker SnoCat #123-001 was not tight, and 1 quart of diesel was released onto the tundra.
12/13/2000	Cause: Human Engineering; Source: Coiled Tubing Unit/Wireline Equip	Diesel-100%	25	25	0	0	100% Recovered; Disposal Location: DS-1H Pit	Reflectors were cleaned off so that drivers would be able to see the edges of the road.	No	Fuel line broke when driver inadvertently drove off the road while traveling in poor vis bility, snow drifts, and where reflectors were covered with snow.
1/30/2001	Cause: Equipment Difficulty; Source: Fittings/Seals/ Connections	Motor Oil - 100%	5	0	5	0	100% Recovered; Disposal Location: DS-1H Pit	None.	No	Hydraulic line broke on vehicle.
2/12/2001	Cause: Human Engineering; Source: Heavy Equip/Mobile Equip/Vehicles	Transmission Fluid-100%	0.3	0.3	0	0	100% Recovered; Disposal Location: DS-1H Pit	Position the portable drip pan under the dipstick prior to checking for leaks.	No	Evidently, the transmission fluid was over filled on a Tucker Sno-cat. When the engine heated up, a bout 1 quart of transmission fluid was released to the snow-covered tundra.

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				Tundra	Water					
2/16/2001	Cause: Equipment Difficulty; Source: Heavy Equip/Mobile Equip/Vehicles	Hydraulic Fluid - 100%	3	0	3	0	100% Recovered; ACS Containment cell pending melting.	Replace failed hose.	No	Hydraulic hose failure on Challenger Cat.
4/15/2001	Cause: Corrosion/ Erosion; Source: Pipe/Flowlines / Hardlines	Produced Water-100%	92400	92400	0	0	Disposal Location: CPF-1 Water Recycle	Line was isolated. Cause is under investigation.	Yes	External corrosion on buried crossing
6/23/2001	Cause: Human Engineering; Source: Heavy Equip/Mobile Equip/Vehicles	Diesel-100%	15	15	0	0	100% Recovered; Disposal Location: CPF1 Oily waste; Absorbents were taken to the NSB Incinerator. Liquids were taken to CPF1 Hydrocarbon Recycle. Solids were taken to the DS1H Oily Waste Pit.	Informed drivers to pay closer attention to driving and road conditions at intersections.	No	Drove fuel truck off of road, into tundra, and rolled onto side while turning on to the 1-H pad access road, spilling diesel to tundra.
7/4/2001	Cause: Procedures; Source: Fittings/Seals/ Connections	Transformer Mineral Oil-100%	0.5	0.5	0	0	100% Recovered; Disposal Location: NSB Incinerator; Absorb sent to NSB.	Removed the absorb left under the transformer	No	Leak from absorb left under equipment.
11/26/2001	Cause: Procedures; Source: Heavy Equip/Mobile Equip/Vehicles	Glycol-50%; Hydraulic Fluid-50%	2	0.5	0	0	None.	-		Vehicle left roadway, striking barricade and causing damage that left transmission fluid and antifreeze on the roadbed and tundra.
8/30/2001	Cause: Equipment Difficulty; Source: Pipe/Flowlines / Hardlines	Crude-100%	0.1	0.1	0	0	100% Recovered; Disposal Location: NSB Incinerator	PAI is reviewing valve design drawings/history and assessing repair options.	No	ROW #9384 leaking bonnet on valve
2/10/2002	Cause:	Hydraulic Fluid -	0.5	0.5	0	0	100% Recovered; Disposal	Inspect all hoses for wear	No	Hydraulic hose failed on a

TABLE C-2 (CONTINUED): KUPARUK SPILLS TO TUNDRA AND WATER

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				Tundra	Water					
	Equipment Difficulty; Source: Fittings/Seals/ Connections	100%					Location: DS-1H Pit; Absorbents sent to NSB Incinerator.	and replace as necessary.		Volvo water truck and leaked onto frozen lake surface.
2/21/2002	Cause: Unknown; Source: Transfer Hoses	Diesel-100%	10.5	0.5		0	100% Recovered; Disposal Location: DS-1H Pit	Currently being investigated.	No	Fuel lines were damaged due to a fire in the connex. Material was released to the pad.
3/4/2002	Cause: Equipment Difficulty; Source: Heavy Equip/Mobile Equip/Vehicles	Diesel-50%, Glycol-50%	3	0	3	0	100% Recovered; Disposal Location: DS-1H Pit	-	No	Fire in truck pump house from pump truck used to build ice roads.
3/5/2002	Cause: Equipment Difficulty; Source: Heavy Equip/Mobile Equip/Vehicles	Motor Oil - 100%	0.1	0	0.1	0	100% Recovered	-	No	Loose fitting with "o" ring on engine, volvo water tanker #188-001.
3/7/2002	Cause: Training; Source: Drums/Containers/Dumpsters	Diesel-2%, Hydraulid Fluid-98%	0.9	0.9	0	0	100% Recovered; Disposal Location: DS-1H Pit	Presently being investigated.	No	Driver drove off road and garbage truck laid over onto snow-covered tundra.
3/9/2002	Cause: Equipment Difficulty; Source: Fittings/Seals/ Connections	Motor Oil-99%, Grease-1%	0.3		0.1	0	100% Recovered; Disposal Location: DS-1H Pit	Operators will be watching to clean globs of grease off Volvo water trucks to keep them from falling off bottom of trucks. Fittings were tightened.	No	Leak from loose fitting on volvo water truck and grease from undercarriage.
4/7/2002	Cause: Procedure; Source: Drums/Containers/Dumpsters	Transmission Fluid-100%	1	1	0	0	100% Recovered; AIC will be thermally remediating the material at their incinerator in Deadhorse.	Discuss driving and road conditions with the driver.	No	Operator of B-70 slid off the gravel raod spilling fluid from a filter on the truck.

TABLE C-2 (CONTINUED): KUPARUK SPILLS TO TUNDRA AND WATER

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				Tundra	Water					
4/15/2002	Cause: Unknown; Source: Flares	Fresh water w/trace of crude-100%	0.9	0.3			-	-	no	The well test flare forced condensation from within equipment, spraying fine mist over large area.
4/27/2002	Cause: Equipment Difficulty; Source: Fittings/Seals/ Connections	Crude-54%; Produced Water-46%	35	1		0	100% Recovered; Disposal Location: DS-1H Pit, As of 5/9/02, 8 1/2 c.y. solids to 1H, 325 bbls liquid to CPF1 EOR. On 6/4/02 additional 9 c.y. to 1H.	Add protective padding or protective devices for critical wellhead componentns as needed when temporary wellhead covers are in use. Increase surveillance on wells equipped with temporary wellhead covers during adverse weather conditions. Increase awareness by developing a means to track the status of wells equipped with temporary shelters or covers.	No	During high wind conditions, well 3H-28 developed a leak from the low pressure pilot bleed valve. The leak depressured and tripped the low pressure pilot, shutting in the well's surface safety valve, stopping the release. During the high wind, the well's temporary wellhead cover was blown loose from the sandbags used to secure the bottom flaps. The flaps impacted the exposed bleed valve on the LP pilot, loosening the packing ring and backing open the valve handle, eventually causing the release.
5/15/2002	Cause: Equipment Difficulty; Source: Fittings/Seals/ Connections	Hydraulic Fluid - 100%	2	1		0	100% Recovered; Disposal Location: DS-1H Pit, Liquids will go to EOR.	-	No	Exact cause unknown. Observed on road and tundra following spring breakup.
7/1/2002	Cause: Equipment Difficulty; Source: Fittings/Seals/ Connections	Hydraulic Fluid - 100%	5		0.1	0	100% Recovered; Disposal Location: DS-1H Pit, Absorbents will be incinerated via NSB. Sheened water taken to CPF1 EOR.	Monitor winter operations more closely for leaks. Inspect snow for leaks prior to pushing off pads. Employee training for spill reporting procedures.	No	Suspect material leaked from heavy equipment. Spill observed in snowpack that was pushed off-pad during winter operations.
7/17/2002	Cause: Equipment	Mineral Oil-100%	1	1		0	100% Recovered; Controlled Burn	-	No	Crack found in cooling fin of transformer during PM.

TABLE C-2 (CONTINUED): KUPARUK SPILLS TO TUNDRA AND WATER

Date of Discharge	Discharge Cause; Spill Source	Material Discharged	Amt Discharged (gal)	Amt of Discharge that Reached Navigable Waters (gal)		Amt of discharge that Reached secondary Contain-ment (gal)	Cleanup Actions	Corrective Action	Enforce-ment Action?	Cause Explanation/ Description of Detection
				Tundra	Water					
	Difficulty; Source: Fittings/Seals/ Connections									Mineral oil had leaked out and dripped on to tundra. Cause of crack is unknown.
7/25/2002	Cause: Equipment Difficulty; Source: Pipe/Flowlines / Hardlines	Crude-41%, Produced Water-59%	10		10	0	95% Recovered; Disposal Location: DS-1H Pit; The fluids will be taken to CPF-1 EOR for water recycle.	The line was depressurized, drained and blinded. The line will remain out-of-service until repairs may be made during the winter 2002/2003.	No	6" production line developed leak.
8/29/2002	Cause: Procedures; Source: Heavy Equip/Mobile Equip/Vehicles	Diesel-100%	672	672	0	0	Recoved diesel used for freeze protection. Sorbents to oily waste dumpsters. Unusable diesel/water mixture to hydrocarbon recycle.	Communicate road position and soft shoulder issues to all drivers. Review and revise LRS Driving Policy.	No	Driver got too close to the soft shoulder of the road and overturned on the tundra.
9/13/2002	Cause: Unknown; Source: Heavy Equip/Mobile Equip/Vehicles	Hydraulic Fluid - 100%	0.1	0.1	0	0	100% Recovered	-	No	A passerby discovered a dirty duck pond containing approximately one cup of hydraulic fluid. This caused sheening on pond edge.
10/1/2002	Cause: Procedures; Source: Heavy Equip/Mobile Equip/Vehicles	Crude-1%; Fresh Water-99%	1	1	0	0	100% Recovered; Disposal Location: CPF-1 Water Recycle	Reiterate to driver and crews that no valves should be opened until there is at least 12 inches of vaccuum on tank.	No	Reiterate to driver and crews that no valves should be opened until there is at least 12 inches of vaccuum on tank.
10/4/2002	Cause: Procedures; Source: Heavy Equip/Mobile Equip/Vehicles	Motor Oil-50%, Hydraulic Fluid-50%	0.5	0.5	0	0	100% Recovered; Disposal Location: Pad 3 Soild Oily Waste Disposal	Improve internal communications about road conditions. Shut down jobs when conditions become too hazardous for work.	No	Driver inadvertently slid off road. Volvo dump truck leaked fluids onto tundra.
12/18/2002	Cause: Human Error; Source: Heavy Equip/Mobile Equip/Vehicles	Muds & Cutting-99%; Hydraulic Fluid-1%	12119	12119	0	0	100% Recovered; Disposal Location: DS-4 (Grind & Inject); 1 c.y. snow contaminated with diesel/hydraulic fluid taken to melt tank at Santa fe, will be recycled at GC2.	Vehicle/trailers inspected for mechanical problems. None found, investigation concludes loss of control led to incident. Taproot investigation pending.	No	Peak maxihaul left roadway and rolled over, spilling 60 yds. muds/cuttings (2000 sq. ft.), 2 gal. hydraulic fluid (12 sq. ft),and 1 quart diesel (6 sq. ft) to tundra.

TABLE C-2 (CONTINUED):
KUPARUK SPILLS TO TUNDRA AND WATER

Date of Discharge	Discharge Cause; Spill Source	Material Discharged	Amt Discharged (gal)	Amt of Discharge that Reached Navigable Waters (gal)		Amt of discharge that Reached secondary Contain-ment (gal)	Cleanup Actions	Corrective Action	Enforce-ment Action?	Cause Explanation/ Description of Detection
				Tundra	Water					Deteriorating weather, truck off road, speed excessive for conditions.
2/5/2003	Cause: Training; Source: Pumps	Diesel-100%	10	10	0	0	100% Recovered; Disposal Location: DS-1H Pit; Contamined snow and gravel was taken to 1H solid waste storage site.	The incident will be reviewed with drill site operators.	No	Drill site operator was pushing a triplex pump on a trailer on drill site 2X. Due to poor visability, operator did not see the edge of the pad and one of the trailer wheels went off the edge, tilting the trailer and pump. Approximately 10 gallons of diesel spilled out the pump's product tank vent. The diesel ran down the edge of the pad and onto the snow covered tundra. The triplex pump product tank holds a total of 2 bbls.
4/26/2003	Cause: Equipment Difficulty; Source: Pipe/Flowlines / Hardlines	Crude-95%; Produced Water-5%	40	40	0	0	100% Recovered; Disposal Location: DS-1H Pit	A clamp was placed over the area of the pipe that is split. All weld packs along the pipeline were wrapped with plastic sheeting that served to channel any fluids leaking from the weld packs into drums used as secondary containment. CPA and contractor personnel visually inspected the line every 12 hours until the line was thawed and pressured tested. The line was evacuated and the split section of pipe replaced. We are currently evaluating the future utility of this line. Investigation of cause is complete.	No	A three phase line at the edge of DS 1A leaked from a split pipe and from three weld pack locations to the snow covered tundra just off the DS 1A Pad.

TABLE C-2 (CONTINUED): KUPARUK SPILLS TO TUNDRA AND WATER

Date of Discharge	Discharge Cause; Spill Source	Material Discharged	Amt Discharged (gal)	Amt of Discharge that Reached Navigable Waters (gal)		Amt of discharge that Reached secondary Contain-ment (gal)	Cleanup Actions	Corrective Action	Enforce-ment Action?	Cause Explanation/ Description of Detection
				Tundra	Water					
3/11/2004	Cause: Equipment Difficulty; Source: Heavy Equip/Mobile Equip/Vehicles	Motor Oil-100%	0.1	0	0.1	0	100% Recovered; Disposal Location: DS-1H Pit	Water tanker #82005 was taken out of service. Job superintendent to meet with VECO operation manager in regards to equipment maintenance problems.	No	Seal leaking on water truck.
5/12/2004	Cause: Equipment Difficulty; Source: Pipe/Flowlines / Hardlines	Crude-30%; Produced Water-70%	2545	2486		0	100% Recovered; Contaminated solids were sent to 1H Pad waste cell. Free liquids were injected into EOR or sent to hydrocarbon recycle. 9 cu. yds. were also taken to G&I in Prudhoe Bay.	The line was shut in and the gauge replaced. An incident investigation was completed.	Yes	Mechanical failure of pressure gauge on a 12-inch pipeline (Heater Production Outlet line) resulting in freezing.
7/15/2004	Cause: Equipment Difficulty; Source: Fittings/Seals/ Connections	Crude-1%; Produced Water-99%	252	42		0	100% Recovered; Disposal Locations: DS-4 (Grind & Inject), CPF-1 Water Recycle	Replaced o-ring. An incident investigation was initiated.	No	O-ring failure on pig receiver.
8/29/2004	Cause: Equipment Difficulty; Source: Heavy Equip/Mobile Equip/Vehicles	Hydraulic Fluid - 100%	3		0.1	0	100% Recovered; Disposal Location: DS-1H Pit	-	No	The support bracket on the Hydraulic Oil Accumulator for the easy ride suspension broke.
1/27/2005	Cause: Human Error; Source: Heavy Equip/Mobile Equip/Vehicles	Diesel-100%	2	0	2	0	100% Recovered; Disposal Location: CPF-1 Hydrocarbon Recycle; Diesel contaminated snow and ice was melted for addition to HC recycle.	-	No	Fueler was fueling heavy equipment and had just placed the fuel nozzle in the left saddle tank of a Water Transport truck and had moved to the second tank, approximately four feet away, to open the lid on the tank. After opening the lid on the second tank, the fueler turned and saw the nozzle come out of the first tank, spraying fuel on the ice road.

TABLE C-2 (CONTINUED): KUPARUK SPILLS TO TUNDRA AND WATER

Date of Discharge	Discharge Cause; Spill Source	Material Discharged	Amt Discharged (gal)	Amt of Discharge that Reached Navigable Waters (gal)		Amt of discharge that Reached secondary Contain-ment (gal)	Cleanup Actions	Corrective Action	Enforce-ment Action?	Cause Explanation/ Description of Detection
				Tundra	Water					
3/14/2005	Cause: Equipment Difficulty; Source: Fittings/Seals/ Connections	Hydraulic Fluid - 100%	1.5	0	1.5	0	100% Recovered; KRU Snow melter - Hydrocarbon Recycle	Tap Root Investigation Conducted.	No	Hydraulic line connection from a Loader with a snow blower attachment became loose allowing hydraulic oil to seep out to the ground and frozen lake surface
3/17/2005	Cause: Unknown; Source: Heavy Equip/Mobile Equip/Vehicles	Class II Fluids-100%	3	2		0	100% Recovered; Disposal Location: DS-1H Pit	-	No	Suspect that fluids were blown into the wind and misted the pad and snow covered tundra when a truck blew down after off loading at the disposal well. CPA is reporting spill to agencies.
3/26/2005	Cause: Corrosion/ Erosion; Source: Pipe/Flowlines / Hardlines	Seawater-30%, Produced Water-70%	51198	48468	0	0	100% Recovered; Disposal Location: DS-1H Pit, CPF-1 Water Recycle, 28475 bbls of fresh water were hauled to the site and used to flush tundra and gravel areas. A total of 8125 bbls of fluids were injected offsite into the EOR system and 46933 bbls were injected into EOR wells at the drillsite. 369 cubic yards of contaminated snow, gravel and tundra material recovered from snowmelters were hauled to the 1H pit.	-	No	Spill caused by hole in pipe due to internal corrosion. Note: the volume estimate was reduced based on determination of the hole size, flow rate and analysis of pressure data leading up to the event.
4/1/2005	Cause: Human Engineering; Source: Heavy Equip/Mobile Equip/Vehicles	Motor Oil-100%	2	2	0	0	100% Recovered	TapRoot investigation will be completed and corrective actions implemented.	No	Vehicle went off road and rolled over causing motor oil to spill onto the tundra.
4/10/2005	Cause: Equipment Difficulty;	Motor Oil-100%	2	2	0	0	100% Recovered; Disposal Location: Other FS HYDR Recycle, Hydrocarbon	Pending TapRoot investigation	No	Truck roll over, while dumping gravel / overburden in the Alpine

TABLE C-2 (CONTINUED): KUPARUK SPILLS TO TUNDRA AND WATER

Date of Discharge	Discharge Cause; Spill Source	Material Discharged	Amt Discharged (gal)	Amt of Discharge that Reached Navigable Waters (gal)		Amt of discharge that Reached secondary Contain-ment (gal)	Cleanup Actions	Corrective Action	Enforce-ment Action?	Cause Explanation/ Description of Detection
				Tundra	Water					
	Source: Heavy Equip/Mobile Equip/Vehicles						Recycle/class 1 gravel cell			flare pit, caused the tractor to leak approximately 2 gallons of motor oil to the gravel pad
4/13/2005	Cause: Equipment Difficulty; Source: Heavy Equip/Mobile Equip/Vehicles	Glycol-90%, Motor Oil-10%	6		0.5	5.5	100% Recovered; Alpine Disposal Well WD-02	Preventative maintenance NI as per taproot investigation.	No	Broken heater hose on a commercial (panel) truck caused a 6 gallon spill of glycol and motor oil (as coolant was lost the engine over heated sending motor oil past the seals. Engine was blown.) The truck was staged on the river for a steaming operation related to the CD3 pipeline project.
4/18/2005	Cause: Equipment Difficulty; Source: Heavy Equip/Mobile Equip/Vehicles	Diesel-100%	0.5	0	0.5	0	100% Recovered; Disposal Location: WD-2 Alpine Class I Disposal; Melted in ACS snow hopper. Hydrocarbons will be skimmed off and the water sendt to WD-02.	-	No	Spill appears to have been caused by a leak in the Thaw Unit's fuel line.
4/20/2005	Cause: Procedures; Source: Transfer Hoses	Crude-5%; Diesel-95%	0.9	0.1	0	0	100% Recovered; Disposal Location: CPF-1 Water Recycle	Review the vaccuum truck procedures with all operators.	No	Written procedure followed incorrectly by vaccuum truck operator (insufficient vaccuum when valve was opened). Majority of fluid was spilled to ice/snow. However, an extimated 1/2 cup actually contacted the tundra.
4/23/2005	Cause: Equipment Difficulty; Source: Heavy Equip/Mobile Equip/Vehicles	Motor Oil-100%	0.1	0	0.1	0	100% Recovered; Disposal Location: WD-2 Alpine Class I Disposal, Impacted ice will be melted, then the hydrocarbons will be skimmed off and the water sent to WD-2.	Welding unit was taken out of service and sent and sent in for repairs.	No	Leaking gasket on a welding unit engine.

TABLE C-2 (CONTINUED): KUPARUK SPILLS TO TUNDRA AND WATER

Date of Discharge	Discharge Cause; Spill Source	Material Discharged	Amt Discharged (gal)	Amt of Discharge that Reached Navigable Waters (gal)		Amt of discharge that Reached secondary Contain-ment (gal)	Cleanup Actions	Corrective Action	Enforce-ment Action?	Cause Explanation/ Description of Detection
				Tundra	Water					
5/1/2005	Cause: Equipment Difficulty; Source: Fittings/Seals/ Connections	Mineral Oil-100%	43	16		0	100% Recovered; 45 cy snow removed, 50 bbl fluid recovered, including snowmelt, and sent to EOR.	Incident investigation in progress.	No	Spill from leaking bushing on electrical transformer.Note: the spilled volume was revised from 48 to 43 gallons after the reservoir was refilled.
6/8/2005	Cause: Procedures; Source: Pumps	Motor Oil-100%	0.1	0.1	0	0	100% Recovered; Oily Waste dumpster	-	No	<1/2 pint of oil leaked from a coalescer oil drain valve on a Sykes pump onto the pad. Snow melt carried the oil off pad creating a sheen on the tundra.
6/28/2005	Cause: Procedures; Source: Tanks	Freshwater w/tr hydrocarb-100%	420	2	0	0	100% Recovered; Disposal Location: DS-4 (Grind & Inject)	The work crew wil lbe retrained on the Tank Cleaning procedure. For future work, containment wil lbe utilized for outside cleaning or the tank will be brought into the Washbay.	No	400-bbl upright was delivered to Washbay for cleaning. Contents of the upright tank were misrepresented and employees did not strap or visially inspect the tank prior to emptying. Additionally, the gauge on the supersucker used to recovered material showed that it was 3/4 full when in fact it was much fuller. As the upright tank was opened, the supersucker was unable to pick up the material. Approximately 10 bbls of fluid spilled out of containment, and onto the gravel pad. An estimated 2 gallons of fluid with a light sheen contacted tundra.

TABLE C-2 (CONTINUED): KUPARUK SPILLS TO TUNDRA AND WATER

Date of Discharge	Discharge Cause; Spill Source	Material Discharged	Amt Discharged (gal)	Amt of Discharge that Reached Navigable Waters (gal)		Amt of discharge that Reached secondary Contain-ment (gal)	Cleanup Actions	Corrective Action	Enforce-ment Action?	Cause Explanation/ Description of Detection
				Tundra	Water					
7/27/2005	Cause: Management System; Source: Heavy Equip/Mobile Equip/Vehicles	Motor Oil-10%; Hydraulic Fluid-90%	10.5	0.3	0		99% Recovered	AES will modify periodic skills re-assessment criteria for heavy equipment operators.	No	Backhoe tipped over due to a slick working area on a slope.
10/26/2005	Cause: Corrosion/ Erosion; Source: Pipe/Flowlines / Hardlines	Crude-22%; Produced Water-78%	16	16	0	0	100% Recovered; Disposal Location: DS-1H Pit	Repair the line using a sleeve or cut-out/replacement technique. Further corrective action to be determined pending the outcome of incident investigation.	No	The DS 3J Production Commonline (12") was found to be leaking at an in-saddle weld pack. The weld pack insulation has been stripped where external corrosion was found. Presumption at this time is that the leak was caused by this corrosion. A root-cause analysis will be completed.
11/6/2005	Cause: Training; Source: Heavy Equip/Mobile Equip/Vehicles	Diesel-100%	0.5	0.5	0	0	100% Recovered; Disposal Location: DS-1H Pit	Discuss with Field Service expeditors the importance of keeping eyes on path. When relocating equipment from location to location, look at the dispatch sheet after hooking up to the equipment and before the vehicle is put in motion. If the need arises to refresh their memory while in route, pull over and come to a complete stop before reaching for the dispatch sheet.	No	Employee picked up triplex pump trailer at DS-2A and was heading east on the Spine road back towards KIC pad. The truck got too close to the edge of the road, resulting in the right side tires of the vehicle and triplex pump trailer leaving the roadway. As employee attempted to steer back onto the road while stopping the vehicle, the triplex pump tipped over on its side.
12/4/2005	Cause: Human Error; Source: Heavy Equip/Mobile Equip/Vehicles	Motor Oil-75%; Hydraulic Fluid-25%	0.8	0.8	0		100% Recovered; Disposal Location: DS-1H Pit	-	No	Crane left the road and fell on its side when the driver fell asleep.
1/28/2006	Cause:	Hydraulic Fluid -	0.5	0	0.5	0	100% Recovered; Disposal	Pending TapRoot	No	Hydraulic hose on a all

TABLE C-2 (CONTINUED): KUPARUK SPILLS TO TUNDRA AND WATER

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				Tundra	Water					
	Equipment Difficulty; Source: Fittings/Seals/ Connections	100%					Location: Beneficial Reuse; Contaminated Snow and ice sent to snow melter for hydrocarbon recycle.	investigation		terrain dump truck. CD3 Project work.
1/29/2006	Cause: Corrosion/ Erosion; Source: Pipe/Flowlines / Hardlines	Produced Water-20%; Methanol-80%	210	105	0	0	100% Recovered; Disposal Location: CPF-1 Water Recycle	-	No	Partially frozen 2" water injection flowline split at an elbow.
1/31/2006	Cause: Equipment Difficulty; Source: Pipe/Flowlines /	NGLs-100%	23	23	0	0	Disposal Location: CPF-1 Water Recycle	-	No	Weld failure due to wind induced vibration.
2/26/2006	Cause: Equipment Difficulty; Source: Heavy Equip/Mobile Equip/Vehicles	Motor Oil-100%	0.5		0.2	0	100% Recovered; Disposal Location: WD-2 Alpine Class I Disposal; Snow was melted in ACS hoppers and sent to WD-02 for Class I disposal	-	No	A Swalling CCI Kenworth tractor had a belly containment filled with snow/ice during a storm. As the engine was warmed, some of the snow/ice in the containment melted along with motor oil which had leaked into the containment. The tractor was moved from the south side of the Tamayak River crossing (#4) to the North side tracking a 3" to 6" track of motor oil along the ice road and within the Tamayak River crossing.
3/9/2006	Cause: Corrosion/ Erosion; Source: Pipe/Flowlines	Produced Water-100%	700	500		200	100% Recovered; Disposal Location: DS-1H Pit, CPF-1 Water Recycle	Incident Investigation will be held to determine corrective actions.	No	Internal corrosion

TABLE C-2 (CONTINUED): KUPARUK SPILLS TO TUNDRA AND WATER

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				Tundra	Water					
	/ Hardlines									
9/9/2006	Cause: Equipment Difficulty; Source: Fittings/Seals/ Connections	Diesel-100%	0.1	0.1	0	0	100% Recovered	-	No	Primary seal failure on ball valve allowed diesel to mist on tundra.
2/11/2007	Cause: Equipment Difficulty; Source: Heavy Equip/Mobile Equip/Vehicles	Motor Oil-100%	0.3	0	0.1	0	100% Recovered; Disposal Locations: DS-1H Pit, CPF-1 Water Recycle; Final disposition has not been deteremined.	-	No	Turbo leak on a pickup
3/20/2007	Cause: Human Engineering; Source: Heavy Equip/Mobile Equip/ Vehicles	Hydraulic Fluid - 100%	0.3	0.3	0	0	100% Recovered; Disposal Locations: Snow melt sent to Class I disposal well at Alpine.	Mechanic work will be inspected for proper installation by unit operator.	No	A hydraulic fluid line between a rolligon tractor and its powered trailer that supports a geotechnical borehole drilling auger was replaced for preventive maintenance but not routed correctly through the harness from which the old hose had been removed. The hose was routed through a location that put it in a pinch point between the rolligon drive unit and the rolligon trailer. When the unit made a sharp turn, the hydraulic line was severed between the forward and rear rolligon untis while on the tundra travelling between gravel pads.
8/12/2007	Valve - Equipment Difficulty; Source:	75% Crude Oil, 25% Produced Water	0.25	0.25	0		Sorbents used to remove oil from valve sleeve and tundra.		No	Faulty valve port-check on grease fitting failed during routine summer maintenance

TABLE C-2 (CONTINUED):
KUPARUK SPILLS TO TUNDRA AND WATER

Date of Discharge	Discharge Cause; Spill Source	Material Discharged	Amt Discharged (gal)	Amt of Discharge that Reached Navigable Waters (gal)		Amt of discharge that Reached secondary Contain-ment (gal)	Cleanup Actions	Corrective Action	Enforce-ment Action?	Cause Explanation/ Description of Detection
				Tundra	Water					
	Fittings/SealConnections									
10/24/2007	Heavy Equipment – Tucker fuel line cap	100% Diesel	0.02	0	0.01		Absorbant used to clean diesel off running boards on tucker. Approximately two gallons of contaminated snow and ice shoveled up. No direct impact to tundra.	Check the stream next summer for hydrocarbons. 1. Modify tundra travel request form to question if job scope includes working on, or crossing over waterways. 2. Evaluate need for all employees operating equipment on tundra to complete tundra management awareness training prior to start of work. 3. Review incident, with focus on tundra travel, non-grounded ice policy, and spill reporting with all CPF3 employees.	No	Approximately 2 ozs of diesel leaked out around the threads of the cap for the fuel fill line. 1 oz fell on the tucker and 1 oz impacted snow covered tundra and stream. Tucker was in use to clean the power line insulators and got stuck while crossing a stream. During the attempt to free the vehicle, diesel was observed leaking onto the running boards. Acs later verified that diesel had impacted the water and snow covering the tundra.

TABLE C-2 (CONTINUED): KUPARUK SPILLS TO TUNDRA AND WATER

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				Tundra	Water					
12/16/2007	External Corrostion	(33% Crude Oil, 67% Produced Water)	4,284	4,284	0		Staged equipment on 2V pad (snow melter, upright tanks, etc.) And constructed ice road and pad near spill site to protect tundra. Constructed 2nd containment (using snow and ice) to store contaminated snow prior to melting. Sorbent boom was deployed to contain spilled product. Clean-up and sampling plans were developed and approved by ADEC. Spilled material was cleaned up using a combinatin of heavy equipment and warm water flushing to recover product. A rehab plan was developed and we are currently monitoring the site for progress and adjsuting the rehab plan as necessary.	1. Repair the line by installing an engineered sleeve. 2. Perform a physical cause analysis to review corrosion mechanisms and current inspection criteria and schedule for improvement. 3. Evaluate the saddle at this location to determine if the design is unique. Implement a strategy to address issues identified that could be present at other saddles. 4. Evaluate all new saddle designs to address avoidance of chafing and moisture accumulation. On going rehabilitation	No	External corrosion at pipeline saddle due to water accumulation

TABLE C-2 (CONTINUED):
KUPARUK SPILLS TO TUNDRA AND WATER

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				Tundra	Water					
12/20/2007	Human Error; valve installation Spill was discovered after breakup occurred on 6/14/08.	100% Crude oil	1	1	0		Wes gromley approved of the use of a weed burner to remove contaminated vegetation in the area. ACS completed cleanup on 6/15/08.	Area will continue to be monitored to assure no rehab is needed.	No	When the 2UVW PO line ruptured last december, we isolated the hole with tundra valves. Downstream of where the hole in the flowline occurred and upstream of the 2V tundra valves, there is a cosasco fitting with a corrosion coupon. These coupons can be pulled and a 2" valve attached to the cosasco fitting. We did this thinking we may need to drain liquids out of the line. We needed a way to drain the pipe with out opening our barrier valves and poss bly increasing the spill. We never opened the valve to drain the line. Apparently, this set up was left in place.
5/25/2008	Equipment damage/ failure	100% Motor Oil	5	3		2	Absorbants used to soak up oil. Water in troughs removed by vac truck. The impacted vegetation burned with weed burner.	1. An industry best practices review will be conducted to help define a dus bus driver training and journey management process. This information will be shared with the Kuparuk vehicle safety team and with other north slope companies that operate heavy equipment for consideration in their respective driver safety programs.		Oil pan split when bus #TBB-001 went off road and bottomed out.

TABLE C-2 (CONTINUED): KUPARUK SPILLS TO TUNDRA AND WATER

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				Tundra	Water					
5/25/2008 (continued)	Equipment damage/ failure	100% Motor Oil	5	3		2		2. A risk assessment, based on this worst case scenario, will be performed to identify each risk associated with driving a bus in the arctic environment. Mitigation measures will be defined and included in the bus driver training and field training officer (FTO) mentoring plans. 3. Determine if a Kuparuk operating procedure should be developed to detail restrictions and controls for vehicles operating IN ADVERSE OR EXTREME ROAD DRIVING CONDITIONS.		
9/18/2008	External Corrosion of 1Y/1R produced oil line (24")	100% Crude Oil	0.1	0.1	0		Vegetative material was removed and placed in an oily waste bag. No soil contamination.	Problem discovered during scheduled corrosion inspection. Repairs completed. Restart of DS 1Y and 1"R began on September 27, and was at pre-shutdown status by 1500 hrs.		Crude oil was found on the tundra due to external corrosion caused by water ingress into the insulation.
11/7/2008	Human/ Operator error	85% Drilling Mud, 10% Glycol, 4% Diesel, 1% Other	95	11	0	84	Scraped up the road, flush and suck drilling mud with vac truck Removed snow with chemical contamination and gravel underneath. Vegetation did not appear to be impacted.	1. Put out field wide bulletin reminding drivers to look for changing road conditions. 2. Present a driving awareness/changing road conditions presentation for the next 3 weekly safety meetings. Final post-breakup inspection complete. No sheen or tundra damage observed.		Driver was unable to negotiate curve under icy conditions

TABLE C-2 (CONTINUED):
KUPARUK SPILLS TO TUNDRA AND WATER

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				Tundra	Water					
2/3/2009	Corrosion / erosion of 1BCFW Injection line (6 inch line)	100% Other	6,930	6,930	0		Recovered 250 bbls of fluid (snowmelt and spilled product) immediately after event. On 4/28, prior to breakup, resumed cleanup by clearing culvert battery and creating sump with 100 BBLS of warm flush water. Continued to contain and dewater the area until snow melted and sheen removed.	The pipeline has been replaced with HDPE-lined, small-diameter pipe that should be impervious to corrosion and should have a higher velocity to prevent solids build-up. Dewater the affected area as outlined in adec approved plan. Confirmation sampling will occur following dewatering.		The leak location was a small split in the 12:00 position on the pipe. The pipe is scheduled for replacment early 2009. A small amount of residual oil from the pipeline may have been present.
2/18/2009	Human Error	50% Lube Oil, 50% Other	0.9	0.1	0		Contaminated show shoveled into bags. Sheen cleanup on 06/07/2009 consisted of trimming grass, burning grass tips with weed-burner, and shovelling road gravel as needed.	Ongoing safe driving awareness Initial spill at road was nonreportable. Upon breakup inspections, sheen was discovered on tundra at location, prompting further cleanup and a report to agencies.		Driver hit drift and veered off hard right. Slid sideway and tipped over on the shoulder of the road. Initial spill at road was nonreportable. Upon breakup inspections, sheen was discovered on tundra at location, prompting further cleanup and a report to agencies.
6/26/2009	Equipment failure Near Well 3I-08	100% Hydraulic Fluid	5	0.1	0		All contaminated gravel removed and contaminated water soaked up with sorbent.	Coil tubing unit was shutdown immediately and repaired.		Sheared fitting on coil tubing unit hydraulic system
8/24/2009	Corrosion / erosion 1B Pad produced water supply line	100% Produced Water	84	21	0		Boom placed on either end of water area, area flushed and contaminated water removed. Sampling in progress to validate cleanup. Contaminated gravel removed and sent to G&I.	Install a sleeve over the leak area to bring the line back into service with a long term plan of full line replacement. Additional inspections were performed on the line to give us confidence in the integrity of the line to bring the line back into service. A long term plan for full ine replacement wil lbe issued.		Mainly internal under-deposit corrosion with minor external corrosion combined, and verified by visual, UT and radiographic inspection.

TABLE C-2 (CONTINUED):
KUPARUK SPILLS TO TUNDRA AND WATER

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				Tundra	Water					
10/13/2009	Equipment difficulty KOC Pad by bus barn	100% Diesel	5	0.05	0		ACS responded to the spill. Absorbents were placed to minimize sheen travel off pad, blade was used to pick up contaminated gravel. Standing water was vacced up.	Monitor area for sheen in the spring		Sheen discovered on standing water by bus parking area. Sheen traveled rapidly across pad and approximately 1 cup made it to the tundra before discovery. All buses were inspected and none found to be leaking. Possible overfill by fueler, or leak from hydraulic lift system on newer style bus.
11/12/2009	Human error Well 2A-27	100% Drilling Mud	1.5	0.04	0		ACS and CPAI engineer delineated area and calculated volume. Cleanup was delayed by blowing snow. Acs used mechanical means to remove contaminated media.	The possibility of unexpected air bubbles is being communicated to crews. In the future, if air suspected, will screw the string into a top-drive, eliminating the possibility of a liquid burp out of the top.		While pulling drill pipe, with the string full of drilling mud, trapped air in the string burped approx. 1 1/2 gal fluid over the top of the tool joint and misted the snow when blown through gap in windwall. The mist was not observed until daylight. Most of the spilled material fell on pad; however, approx. 4 ounces landed snow covered tundra. Spilled material did not penetrate through the snow.
4/8/2010	Suspected External Corrosion / erosion 18" flowline from 3-H Pad at VSM #415	100% Crude Oil	1	1	0		Contaminated snow and tundra grass top removed	Immediate source control: shut-in pad, evacuated and depressured flowline. Non-destructive evaluation (NDE) was made on the area and a sleeve was designed and fabricated. Installation of the sleeve commenced on april 12 with startup of production on April 13.		Inspection of the site found a pin-hole caused by external corrosion under insulation. This location had been previously targeted for stripping and further inspection, planned in the next few weeks.

TABLE C-2 (CONTINUED): KUPARUK SPILLS TO TUNDRA AND WATER

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				Tundra	Water					
6/12/2010	Equipment failure Valve HV-2A3002	100% Produced Water	8	8	0		Area was delineated and shoreseal and absorbent boom placed. Free liquid was recovered, and water was used to flush and melt snow. Oiled grass was trimmed and continued snowmelt was managed.	Ensure pipe fitters consistently remove all coating (done by manufacturer) if any slight differences are present.		Leaking blind flange connection on tundra valve HV-2A3002.
6/24/2010	Human Error	46% Glycol, 18% Diesel, 18% Motor Oil, 18% Hydraulic	1.38	1.38	0		Absorbents were used to soak up spilled material and clean spilled material off of plant matter. Conducted controlled burn of impacted area per ADEC approval.	Conduct incident investigation. Focus on driving safety during safety meetings.		Operator drove vehicle too close to shoulder of road. Vehicle went down bank and tipped over onto the tundra. Along KIC access road near end of runway
7/2/2010	Hose Failure 200 Yards south of 1H Pad entrance	100% Hydraulic Fluid	15.5	0	1.2		Gravel removed by supersucker; boom place on pond and sheen water vac'ed up; vegetation on edge of the pond cleaned with absorbs.	A comprehensive hose fabrication training program is being developed for all mechanics doing this task; the vendor, who stocks the drawers, has been contacted about the mixed fittings.		Water pump hose failure. Upon investigation, found that a 2-wire fitting had been used on a 4-wire hose, due to all fittings being mixed in one drawer and difficulty distinguishing.
1/9/2011	Pressure related Well 2L-320 Doyon 15 Rig	100% Drilling Mud	1,890	168	0	714 into bldg.	ACS responded immediately and the impacted area was delineated. The Kuparuk spill response team removed all snow over tundra that contained any visual drilling mud. Impacted snow on-pad was then removed. Wipe-down of impacted pipeline and valve shelters followed. Free liquid within the doyon 15 drilling rig was removed for beneficial reuse. The remaining material was washed-down over	Immediately following the release, the well was shut in and mud was returned to the well bore, stabilizing the subsurface conditions. When drilling commenced, mud weight was increased. Following the investigation, preventive measures were assigned: 1) Change the policy for coming off bottom to include requiring any differences between the mud fill volume and the trip sheet expected fill volume to be announced over the intercom for every		The well took a "gas kick" while tripping out of the hole. The root cause investigation found the following: gas was entrained in the oil-based mud and moving up the well bore, but the rig drilling team wasn't aware of it. When the rig drilling team did see a very small amount of flow from the well, they decided they would circulate more mud into the well. The drilling team thought they would have time to react if flow

TABLE C-2 (CONTINUED):
KUPARUK SPILLS TO TUNDRA AND WATER

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				Tundra	Water					
							containment and cleaned with absorbs. During summer, sampling was conducted to confirm cleanup. An additional 2 CY of impacted gravel was removed. Sample results were reviewed with adec for agreement that the site is now clean.	stand that is removed, to ensure the full drilling team is aware of the conditions as they happen.		from the well increased.
1/9/2011 (continued)	Pressure related Well 2L-320 Doyon 15 Rig	100% Drilling Mud	1,890	168	0	714 into bldg.		2) Review the ConocoPhillips well shut in requirements to ensure consistency with communications given to rig crews. Provide more clarity on what conditions require a well shut in. Communicate to all rigs the requirement that all crews review the conocophillips shut in policy at each hole section. 3) conduct a training on oil-based mud (OBM) properties to all rig team members with an emphasis on the fact that obm has a high gas solubility which will entrain gas liquids at shallow depths in the well bore, giving less time to react than expected.		
5/6/2011	Human error Valve Intersection under 2M-2A jumper line.	80% Crude Oil, 20% Produced Water	25	25	0		Spill to area heavily drifted in with snow. Hand shovels and a wa k behind bobcat were used to remove snow. Contaminated snow was melted and taken to water recycle. Removed scaffolding, wiped down piping, and removed contaminated snow from the top of pipe rack to the	1. A formal resource plan will be included in the future. The meltwater pigging pre-planning documents wil linclude required manpower and available experience. 2. Discuss in safety meeting and morning tailgate meetings the need to secure all blow down and bleeder		Loosely capped jic fitting on hi-point vent valve. Leak from closed high point vent valve on 10" produced water injection jumper line at 4-corners.

TABLE C-2 (CONTINUED):
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				Tundra	Water					
							tundra (approx. 40 yds). On 5/12/11 it was determined that spilled material had reached the tundra. NRC and ADEC were called.	valves before leaving the work site. Review the existing plugging andcapping policy, suggest verbiage to be added to the policy requiring plugs to be installed in any unmanned vent valves located over tundra.		
5/6/2011 (continued)	Human error Valve Intersection under 2M-2A jumper line.	80% Crude Oil, 20% Produced Water	25	25	0		Approximately 1/4 yd of sediment was removed from a trough and the area was dewatered. Absorbent boom was placed. Continued dewatering and monitored the site through breakup. An assessment was made and no further treatment was deemed necessary. Fertilizer was applied to aid in revegetation of scraped area. 7/24/11 clean up complete and final samples taken 7/9/11. Samples were at allowable limits and determination that the spill incident is closed per ADEC standards.			
5/24/2011	Flange leak / failure 2K Pad	100% Produced Water	3	3	0		Consulted with ADEC on cleanup strategy. Determined that allowing snowment to naturally flush the area was the best management option. Samples are periodically collected and analyzed for conductivity to determine amount of contamination present. Monitored the site throughout breakup.	Repair or replace valve.		Leak on 6" produced water line slowly dripping from flange. Worker discovered fluid slowly dripping from flange to tundra below. Estimated that the line had been dripping for approximately 24 hours.

TABLE C-2 (CONTINUED): KUPARUK SPILLS TO TUNDRA AND WATER

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				Tundra	Water					
							Inspected the area several times after all snow melted. No sheen, distressed tundra or other evidence of contamination at the site.			
8/1/2011	Human error Water Inj. flowline DS1G access road	20% Crude Oil 80% Produced Water	0.5	0.25			Absorbs were used to clean up spill at the time of occurrence. Cpai received a delayed report from the contractor. Acs responded when cpai became aware of the spill and performed additional minor spot ceanup.	Contractor is conducting an incident investigation		Crew was welding a flange and did not blind it or place containment under it. Spill occirred from open ended, uncovered pipe. Crew was repositioning pipe when leak occurred. Approximately 1 quart of spilled material landed on scaffolding and plywood, and another quart spilled to tundra and water below the scaffolding.