BP EXPLORATION (ALASKA) INC.

OIL DISCHARGE PREVENTION AND CONTINGENCY PLAN

ENDICOTT OPERATIONS AND BADAMI PIPELINE
NORTH SLOPE, ALASKA

VOLUME 1 OF 2, RESPONSE ACTION PLAN

APRIL 2012

BP EXPLORATION (ALASKA) INC.

ENDICOTT OPERATIONS AND BADAMI PIPELINE OIL DISCHARGE PREVENTION AND CONTINGENCY PLAN

Volume 1 of 2, Response Action Plan

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BP EXPLORATION (ALASKA) INC.

ENDICOTT OPERATIONS AND BADAMI PIPELINE OIL DISCHARGE PREVENTION AND CONTINGENCY PLAN

MANAGEMENT APPROVAL AND RESOURCE COMMITMENT STATEMENT

This plan is consistent with the requirements of the National Contingency Plan and the Alaska Federal/State Preparedness Plan for Response to Oil and Hazardous Substance Discharges / Releases (Area Contingency Plan). It is approved for implementation as herein described. Manpower, equipment and materials will be provided as required in accordance with this plan.

BP Exploration (Alaska) Inc.'s approach to oil spill response will be based on the following priorities:

1. Safety of personnel
2. Protection of the environment
3. Protection of facilities

Bruce Price
Area Operations Manager North

Date

4/13/12

BP EXPLORATION (ALASKA) INC.

P.O. Box 196612
Anchorage, Alaska 99519

900 East Benson Boulevard
Anchorage, Alaska 99508

(907) 564-5111 - telephone

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RECORD OF REVISIONS – VOLUME 1

REVISION NUMBER	REVISION DATE	SUMMARY OF REVISION CHANGE
1	January 2013	Updates to Figure 1-2 (Incident Management Team), and Table 1-2 (BPXA Contact List).
2	February 2013	Updates to contact numbers for North Slope Borough personnel in Table 1-3: Agency Reporting Requirements for Oil Spills. Revision of Crucial 13/30 skimmer recovery rate in Table 1-13: Oil Recovery Rate.

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°F	degrees Fahrenheit
°C	degrees Celsius
μm	micrometer
AAC	Alaska Administrative Code
ACS	Alaska Clean Seas
ADEC	Alaska Department of Environmental Conservation
ADFG	Alaska Department of Fish and Game
ADNR	Alaska Department of Natural Resources
ADW	Alaska Drilling and Wells
Alyeska	Alyeska Pipeline Service Company
AOGCC	Alaska Oil and Gas Conservation Commission
ARRT	Alaska Regional Response Team
ASTM	American Society for Testing and Materials
ATV	all-terrain vehicle
BAT	best available technology
bbl	barrels
bbl	barrels per linear foot
BOP	blowout preventer
bopd	barrels of oil per day
boph	barrels of oil per hour
BPXA	BP Exploration (Alaska) Inc.
BSEE	Bureau of Safety and Environmental Enforcement
BST	Business Support Team
CFR	Code of Federal Regulations
CM/ER	Crisis Management/Emergency Response
COTP	Crude Oil Transmission Pipeline
cP	centiPoise
DOT	U.S. Department of Transportation
EOR	enhanced oil recovery
EPA	U.S. Environmental Protection Agency
ERD	extended reach drilling
ESD	emergency shutdown
ESI	Environmental Sensitivity Index
FLIR	Forward Looking Infrared
FOSC	Federal On-Scene Coordinator
G&I	Grind and Inject
g/cm^3	grams per cubic centimeter
GOR	gas-to-oil ratio
GPB	Greater Prudhoe Bay

gpm	gallons per minute
GPR	ground penetrating radar
GPS	global positioning systems
GRS	geographic response strategy
HAZWOPER	Hazardous Waste Operations and Emergency Response
Hz	hertz
IBR	International Bird Rescue
IC	Incident Commander
ICS	Incident Command System
IMS	Incident Management System
IMT	Incident Management Team
LEL	lower explosive limit
LOSC	Local On-Scene Coordinator
MAD	Mutual Aid Drill
MESA	Most Environmentally Sensitive Areas
MHz	mega hertz
mm	millimeter
mm/min	millimeters per minute
mPa.s	milli Pascal seconds
mph	miles per hour
MPI	Main Production Island
MPU	Milne Point Unit
NIMS	National Incident Management System
NOAA	National Oceanic and Atmospheric Administration
NPDES	National Pollutant Discharge Elimination System
NPREP	National Preparedness for Response Exercise Program
NRC	National Response Center
NSB	North Slope Borough
NSSRT	North Slope Spill Response Team
O&M	Operations and Maintenance
ODPCP	oil discharge prevention and contingency plan
OIM	Offshore Installation Manager
OPA 90	Oil Pollution Act of 1990
OSHA	Occupational Safety and Health Administration
OSM	Onshore Site Manager
OSRO	Oil Spill Removal Organization
OTL	Operations Team Lead
PBOC	Prudhoe Bay Operations Center
PPE	personal protective equipment
QI	Qualified Individual
RPIC	Responsible Party Incident Commander

RPS	Response Planning Standard
S&OR	Safety & Operational Risk
SAR	Synthetic Aperture Radar
Savant	Savant Alaska LLC
SCAT	Shoreline Cleanup Assessment Technique
SDI	Satellite Drilling Island
SOSC	State On-Scene Coordinator
SPCO	State Pipeline Coordinator's Office
SRT	Spill Response Team
SSO	Site Safety Officer
TBD	to be determined
TL	Team Lead
USCG	U.S. Coast Guard
VHF	very high frequency
yd^3	cubic yard

INTRODUCTION

This Oil Discharge Prevention and Contingency Plan (ODPCP) covers Endicott operations and facilities and the Badami crude oil transmission pipeline, which are operated by BP Exploration (Alaska) Inc. (BPXA). The Endicott field is offshore of the Alaska North Slope in the Beaufort Sea, about 15 miles east of Prudhoe Bay. Facilities are approximately 2.5 miles seaward of the Sagavanirktok River Delta, shoreward of the barrier island, in water up to 14 feet deep. The Endicott facility includes three manmade gravel islands in the Beaufort Sea which hold drilling and production systems, approximately 120 wells, the base operations center and support facilities, and a crude oil transmission pipeline running from Endicott to Pump Station 1. The Badami pipeline runs from the Badami production facility (31 miles east of Deadhorse, Alaska) to the Endicott tie-in.

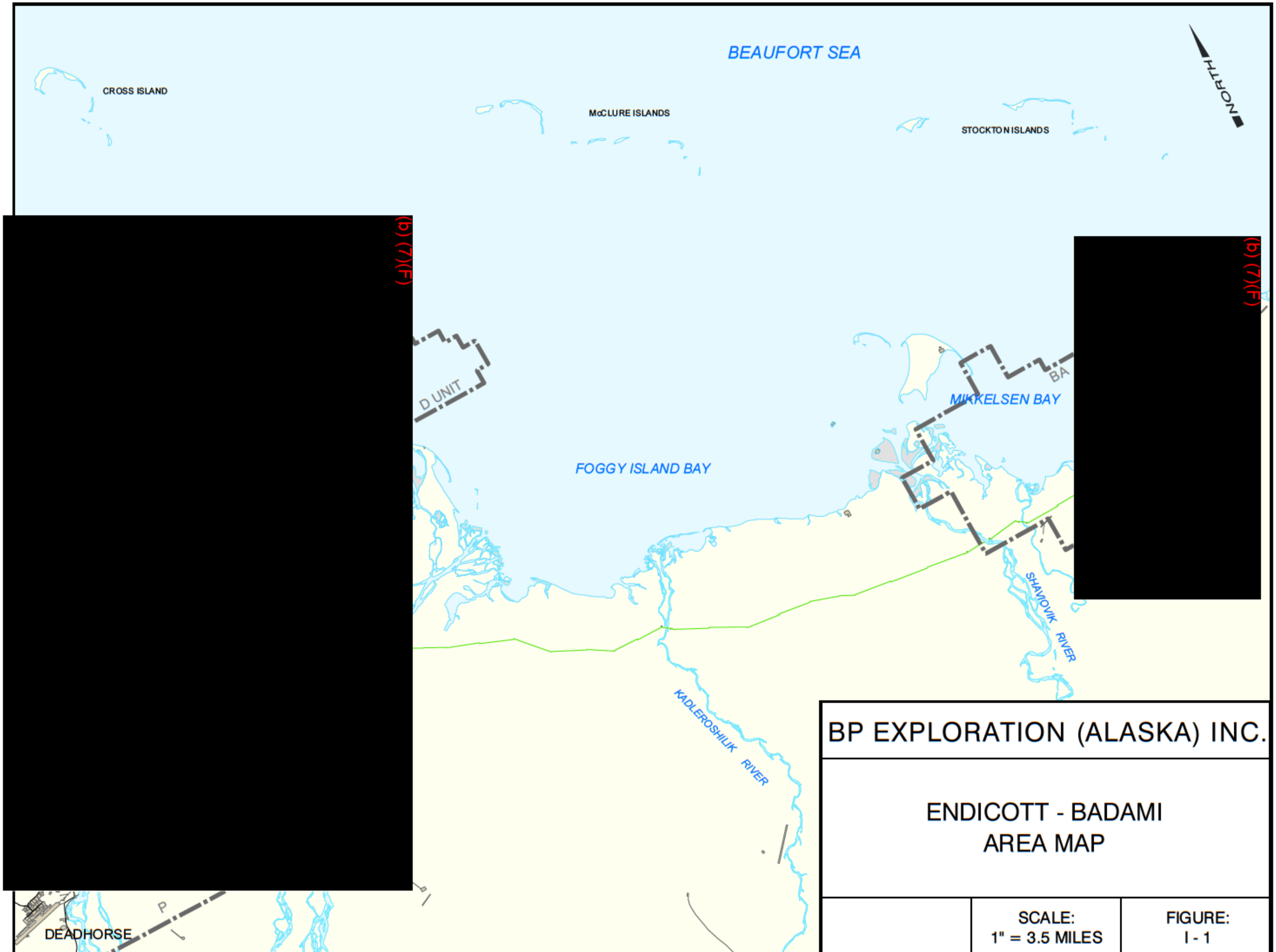
Figure I-1 illustrates the location of Endicott and the Badami pipeline. Figure I-2 is a detailed illustration of the bathymetry near the Endicott facilities.

The ODPCP addresses oil spill prevention and response requirements promulgated by the State of Alaska in Title 18, Chapter 75 of the Alaska Administrative Code (AAC). It is comprised of five parts consistent with 18 AAC 75.425(d)(2). As allowed under 18 AAC 75.425(e)(2), the ODPCP is represented by two volumes: Volume 1, Response Action Plan, and Volume 2, Prevention Plan. The Response Action Plan (Volume 1) is contained herein.

The Response Action Plan addresses federal oil spill planning regulations of the U.S. Department of Transportation (DOT) for Endicott and Badami, and the Bureau of Safety and Environmental Enforcement (BSEE) for Endicott.

The Response Action Plan, with the resources and equipment listed herein, is a planning document that demonstrates the potential response capability available to respond to an oil spill from tanks, pipelines, wells and other equipment covered by this plan. It is not a guarantee of what will occur, or the resource deployment sequencing that will be used in an actual spill event. Nothing in this plan is intended to limit the discretion of persons in charge of an actual spill response to take the actions deemed necessary to maximize the effectiveness of the response, consistent with safety considerations. Response operations in a spill event will be tailored to meet actual circumstances.

This plan incorporates by reference some information provided in the Alaska Clean Seas (ACS) *Technical Manual*.



BP EXPLORATION (ALASKA) INC.		
ENDICOTT - BADAMI AREA MAP		
	SCALE: 1" = 3.5 MILES	FIGURE: I - 1

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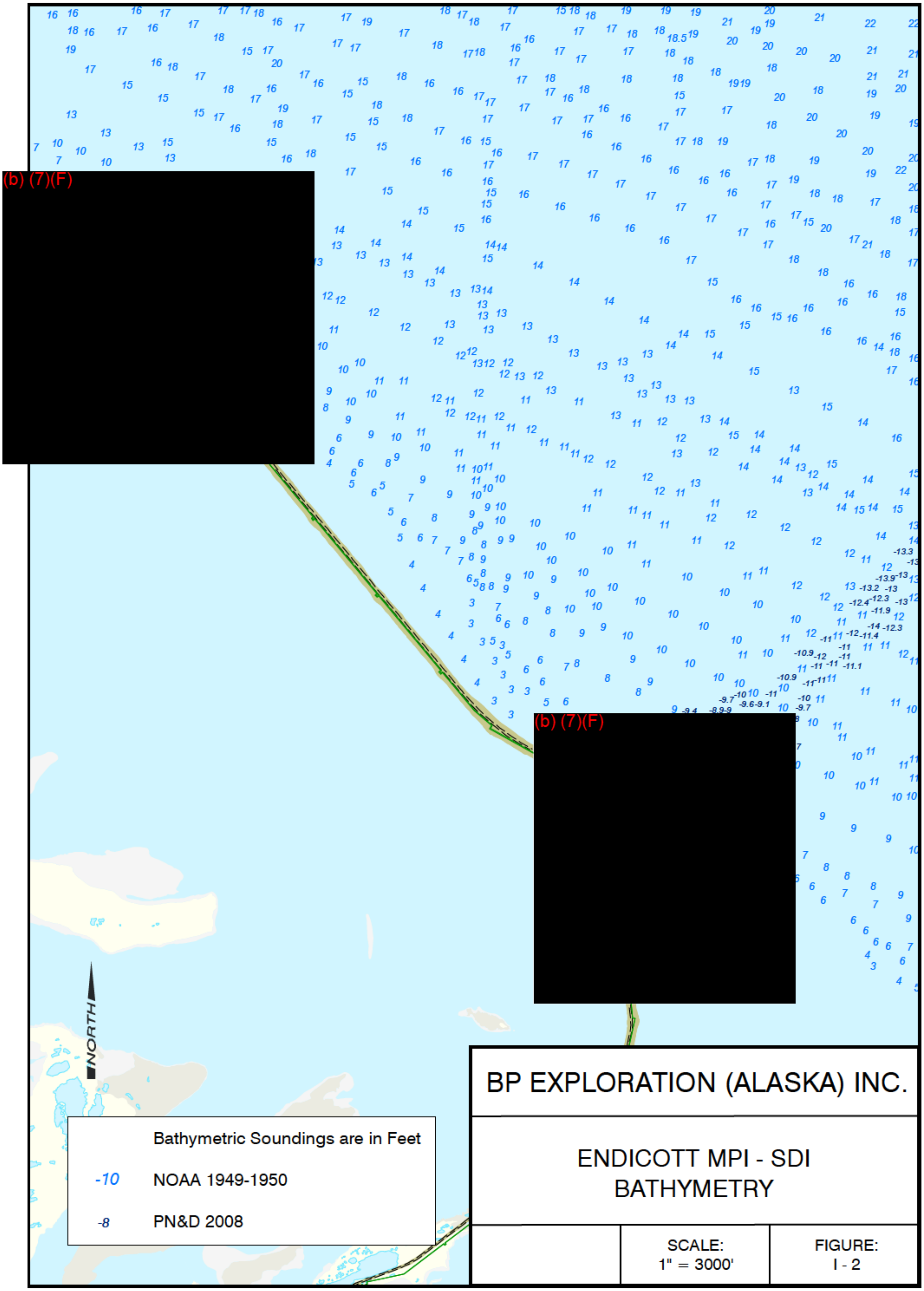

Endicott_Bathy.mxd

PLAN DISTRIBUTION

The Response Action Plan is maintained on the BPXA intranet website, which is accessible by BPXA employees and contractors. Hard copies of the plan or electronic copies on CD are distributed to regulatory agencies and emergency operations centers. Additional copies are in the Anchorage Crisis Center, the Safety & Operational Risk (S&OR) Department, and at ACS. A record of plan distribution is maintained by the S&OR Department.

UPDATING PROCEDURES

The ODPCP is reviewed annually and revised and updated when changes occur. Below is a list of key factors that may cause revisions to the plan:

- New developments,
- New pipeline construction or purchase,
- Change to worst case discharge volume(s),
- Change in commodities transported,
- Change in oil spill removal organizations,
- Change in Qualified Individual,
- Changes in a National Contingency Plan or Area Contingency Plan that have a significant impact on the appropriateness of response equipment or response strategies,
- Change in response procedures, and/or
- Change in ownership.

Routine updates are submitted for Alaska Department of Environmental Conservation (ADEC) review within five days after the date of proposed change. Other modifications to the plan are considered amendments, which are reviewed and approved by ADEC. Revisions to the plan are documented in the Record of Revisions table at the beginning of the plan and posted on the BPXA intranet site for employee and contractor reference. Hard copies of the changed pages or new CDs (for electronic copy holders) are distributed to plan recipients, including regulatory agencies and emergency operations centers. Upon receipt of revisions, the recipient replaces plan pages (hardcopy) or the previous CD, as instructed in the distribution letter. It is the responsibility of each plan recipient to ensure that updated pages are promptly incorporated into the plan and that previous CD revisions are discarded or archived.

PLAN RENEWAL

The plan renewal cycle involves a number of state and federal approvals, as shown below.

REGULATING AGENCY	RENEWAL CYCLE	EXPIRATION DATE
ADEC	5 years	March 27, 2017
DOT	5 years	December 17, 2013
BSEE	5 years. Following 30 CFR 254.53, BSEE Facility Response Plans developed under State requirements can be submitted according to State's requirements.	May 22, 2012

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STATE OF ALASKA

DEPT. OF ENVIRONMENTAL CONSERVATION
DIVISION OF SPILL PREVENTION AND RESPONSE
INDUSTRY PREPAREDNESS PROGRAM

SEAN PARNELL, GOVERNOR

555 Cordova Street
Anchorage, AK 99501
PHONE: (907) 269-3094
FAX: (907) 269-7687
http://www.dec.state.ak.us/

March 27, 2012

File No: 305.30
(BPXA End-Bad)

Mike Bronson
Eppie Hogan
BP Exploration (Alaska) Inc.
P.O. Box 196612
Anchorage, AK 99519-6612

Subject: **BP Exploration (Alaska) Inc. Oil Discharge Prevention and Contingency Plan for Endicott Operations and Badami Pipeline, North Slope, Alaska. Plan Number 11-CP-4130. Plan Approval**

Dear Mr. Bronson and Ms. Hogan:

The Alaska Department of Environmental Conservation (department) has completed our review of your application for the above referenced Oil Discharge Prevention and Contingency Plan (plan) dated December 2011. The department coordinated the State of Alaska's public review for compliance with 18 AAC 75, using the review procedures outlined in 18 AAC 75.455. Based on our review, the department has determined that your plan is consistent with the applicable requirements of the referenced regulations and is hereby approved.

This approval applies to the following plan:

Plan Title:	**BP Exploration (Alaska) Inc. Oil Discharge Prevention and Contingency Plan for Endicott Operations and Badami Pipeline, North Slope, Alaska**
Supporting Documents:	**Alaska Clean Seas (ACS) Technical Manual, © June 2010, as revised and updated**
Plan Holder:	**BPXA Exploration (Alaska) Inc. 900 East Benson Boulevard P. O. Box 196612 Anchorage, AK 99519-6612**

Covered Facilities: **Production and drilling operations conducted within the Endicott Operations Area, operation of the Endicott crude oil transmission pipeline from the Main Production Island to the Eastern Operations Center, and also the Badami crude oil transmission pipeline from the Badami Development Area to the Endicott pipeline**

PLAN APPROVAL: Approval of the referenced plan is hereby granted, effective **March 27, 2012**. 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).

1. **Notice of Changed Relationship with Response Action Contractor.** Because the plan relies on the use of response contractors for its implementation, BP Exploration (Alaska) Inc. (BPXA) must immediately notify us in writing of any change in the contractual relationship with the plan holder's response action contractors, 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. **Management Approval and Manpower Authorization Form**. A signed copy of the Management Approval and Manpower Authorization form must be provided in the final plan distribution or submitted to the department in accordance with 18 AAC 75.425(e)(c)(3).

   This condition is reasonable and necessary to ensure that a statement signed by a person with appropriate authority to commit the oil discharge prevention and response resources necessary to implement the plan is submitted as required by 18 AAC 75.425(e)(c)(3).

2. **Blowout Contingency Plan.** A copy of the Blowout Contingency Plan (BCP) must be maintained at the Endicott facility and made available to the department upon request.

   This condition is necessary to ensure that the plan holder is prepared to control a potential well blowout. The department will review the blowout contingency plan when performing site inspections and/or in Anchorage BPXA offices. 18 AAC 75.425(e)(1)(I), 18 AAC.445(d)(2), and 18 AAC 75.480.

3. **Revision to Table 2-9: Visual Surveillance Requirements.** Table 2-9 is lacking visual surveillance information for the Badami crude oil transmission pipeline. BPXA must include an entry reflecting that aerial surveillance is performed on the Badami crude oil transmission pipeline weekly unless precluded by safety or weather, in accordance with 18 AAC 75.055(a)(3). This information will be shown in revisions for the first amendment to the approved plan.

   This condition is necessary to ensure that the plan is consistent with regulatory requirements and accurately describes the visual surveillance activity performed for this pipeline. 18 AAC 75.425(e)(2)(E) and 18 AAC 75.055(a).

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. BPXA must send three complete plan copies to the Exploration, Production & Refineries Section. 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 27, 2017**. 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 Jeanne Swartz at (907) 269-7604 or at jeanne.swartz@alaska.gov.

Sincerely,

Betty Schorr

Betty Schorr
Program Manager

Attachment: Summary of Basis for Department Decision

Enclosure: Certificate of Approval, Number 12CER-011

Electronic cc: (w/o enclosure)

Scott Pexton, ADEC
Tom DeRuyter, ADEC
John Ebel, ADEC
Gordon Brower, NSB
Roy Varner, Sr., NSB
Hon. Charlotte Brower, NSB
Jake Adams, NSB
John Boyle, III, NSB
Richard Camilleri, NSB
C-Plan Reviewer, ADNR
Tony Cabinboy, NSB
Christy Bohl, BSEE
Mike Thompson, JPO
Jack Winters/Todd Nichols, ADFG
Matt Carr, USEPA
Melanie Barber, USDOT
MSTC Shawn Erwin, USCG
MST1 Brian Schughart, USCG
LCDR Bradley Clare, USCG
Pam Miller, Northern Alaska Environmental Center

Susan Harvey, Harvey Consulting
Legal Director, Trustees for Alaska
Tony Parkin, BPXA
Lydia Miner, SLR

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

Certificate Number: **12CER-011**

Plan Number: **11-CP-4130**

Name of Plan: **BP (Exploration) Alaska, Inc. Endicott Operations and Badami Pipeline North Slope Production Oil Discharge Prevention and Contingency Plan**

Covered Facilities: **Production and drilling operations conducted within the Endicott Operations area and operation of the Badami crude oil transmission pipeline from the Badami Development Area to the Endicott Pipeline**

Address: **BP (Exploration) Alaska, Inc., 900 East Benson Boulevard, Anchorage, AK 99508 or P. O. Box 196612, Anchorage, AK 99519**

Telephone: **(907) 564-5111** Fax: **(907) 564-5020**

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

Effective Date of Approval: **March 27, 2012** Expiration Date: **March 27, 2017**

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 03.27.2012

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

STATEMENT OF CONTRACTUAL TERMS

AS REQUIRED UNDER AS 46.04.30, AS 46.04.035 and 18 AAC 75.445(l) (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 Plan, Endicott Operations and Badami Development Area
PLAN HOLDER: BP Exploration (Alaska), Inc.

This statement is a certification to the Alaska Department of Environmental Conservation summarizing the contract between BP Exploration (Alaska), Inc. the oil discharge prevention and contingency plan holder (hereinafter "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 (hereinafter "CONTRACTOR"), executed July 1, 2005, and the original of which is located at Alaska Clean Seas, 4220 B Street, Anchorage, Alaska, 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 a 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.

Signature [signature] Date 7/14/05

Name: CRAIG L WIGGS

Title: DELIVERY UNIT MANAGER

For: BP Exploration (Alaska), Inc.
PLAN HOLDER

I hereby certify that as a 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.

Signature [signature] Date 7/14/05

Name: Brad Hahn

Title: President

For: Alaska Clean Seas, CONTRACTOR

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

As the Badami pipeline operator, BP Exploration (Alaska) Inc. (BPXA) and Alaska Clean Seas (ACS) will respond to oil spills associated with the Badami crude oil transmission pipeline downstream of mainline block valve 1305, Savant Alaska LLC (Savant) is responsible for spills associated with the Badami wells and production facility.

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

Table 1-1 lists immediate response actions for an oil spill. Figure 1-1 provides a flow chart for immediate oil spill notification and reporting. Figure 1-2 illustrates the Incident Management Team (IMT) structure.

A spill response operation on the North Slope falls into one of three categories listed below.

A Level I spill has limited duration and impacts, and can be handled by a BPXA response organization with immediately available local resources. Typical characteristics of a Level I spill are as follows:

- Less than one shift of the IMT in duration,
- Does not require mutual aid from other operators, and
- No written Incident Action Plan.

A Level II spill is more complex, longer in duration, and characterized by more widespread effects. The activation of a BPXA response organization is composed of response resources available in Alaska. Typical characteristics of a Level II spill are as follows:

- More than one shift of the IMT in duration,
- Team members drawn from off-duty North Slope-based personnel and Anchorage-based personnel,
- Agency involvement and formation of a Unified Command, and
- Written Incident Action Plan.

A Level III spill is major, complex or compound in nature, has pronounced impacts on people, the environment and/or property, and involves response operations for an extended period of time. A Level III spill involves the activation of all elements of the Incident Command System (ICS), supplemented by response resources from inside and outside of Alaska. The location of the Incident Command Post is dependent upon many factors, including the location, type, and size of the incident. The Incident Command Post (location where the IMT operates) for a Level III incident at Endicott would most likely be located in the Prudhoe Bay Operations Center (PBOC).

The response organization structure described in this plan is based on the ICS and accommodates each level of response. All three levels involve activation of the Spill Response Team (SRT), an IMT and/or the

Business Support Team (BST). As necessary, BPXA uses the resources of other North Slope operators through ACS, Mutual Aid, spill response cooperatives, and contractors.

TABLE 1-1: IMMEDIATE RESPONSE CHECKLIST

LEVEL I, II, & III SPILLS	

FIRST RESPONDER	☐ Assess safety of situation, determine whether source can be stopped, and stop the source of spill if possible. The first responder only takes action to the level they are trained to take.
	☐ Immediately report the spill by calling 659-6900 or calling on Radio Channel 1. Immediately notify supervisory personnel after reporting the spill.
	☐ Provide information on:
	  ☐ Personnel safety
	  ☐ Source of the spill
	  ☐ Type of product spilled
	  ☐ Amount spilled
	  ☐ Status of control operations

RADIO DISPATCHER/ OPERATOR FOR ENDICOTT SPILL	Immediately notify: ☐ ACS Environmental Technician: Call 6541 or Beeper 313 ☐ Endicott Safety: Call 6666 or Beeper 911 ☐ Endicott Offshore Installation Manager: Call 6555 or Beeper 121
DEPUTY OPERATIONS SECTION CHIEF	☐ Report to scene, if required. ☐ Make an initial assessment of the spill and associated safety and environmental issues. ☐ Stop the source of spill if possible. ☐ Initiate actions to report spill to agencies. ☐ Upon arrival on scene, begin response operations. If necessary, mobilize SRT and on-site equipment required to control and clean up spill. ☐ Supervise control and recovery operations. Upon completion, ensure appropriate storage and disposal of oily wastes/materials. ☐ Confirm success of cleanup and plan remediation if required. ☐ Assess response activities. If response is adequate, remain at Level I. If additional capabilities are needed, go to Level II or Level III response below.
LEVEL II & III SPILLS	
SAFETY OFFICER	☐ Account for the safety of personnel. ☐ Ensure establishment of site-entry and exit procedures, including lower explosive limit (LEL) and air monitoring, and personnel and equipment decontamination. ☐ Determine if a threat of fire or explosion exists. If a threat exists, suspend control and/or response operations and notify Fire/Safety Department. ☐ Determine appropriate personal protective equipment (PPE) and brief site workers.
ENVIRONMENTAL ADVISOR	☐ Make immediate phone notification to the agencies. ☐ Initiate necessary permits for agency approval. ☐ Prepare cleanup and waste management plan for agency approval. ☐ Ensure agency notifications are complete and maintain follow-up notifications on a periodic basis and whenever there is a significant change in the course of a reported incident.

TABLE 1-1 (CONTINUED): IMMEDIATE RESPONSE CHECKLIST

INCIDENT COMMANDER	☐ Activate all or part of the IMT and the Command Post. ☐ Notify the BP Notification Center at 1-800-321-8642. The BP Notification Center will contact BPXA's BST Duty Officer and share information provided by the Incident Commander (IC). Provide the BP Notification Center with a contact name and phone number. ☐ Notify Qualified Individual (QI). ☐ Continue internal and external notifications. ☐ Maintain communications with Anchorage Crisis Center. ☐ Coordinate staff activity. ☐ Manage incident operations and approve release of major resources and supplies.
OPERATIONS SECTION CHIEF	☐ Activate ACS 659-2405 (24 hours). ☐ Activate Mutual Aid through ACS as necessary. Establish staging areas as required. ☐ Provide the Logistics Section Chief with information on initial equipment, staff, material, and supply needs. ☐ Supervise control and recovery operations. ☐ Ensure appropriate storage and disposal of oily wastes/materials.
PLANNING SECTION CHIEF	☐ Ramp up Planning Section. ☐ Ensure Agency Notifications have been made and updates are provided. ☐ Compile and display status information in Command Post. ☐ Assist in development of planning process. ☐ Document aspects of the response. ☐ Provide environmental support as needed.
LOGISTICS SECTION CHIEF	☐ Order equipment, personnel, material, and supplies as requested. ☐ Provide transportation support. ☐ Provide support for all field operations and Command Post operations.
LEVEL II & III SPILLS (CONTINUED)	
FINANCE SECTION CHIEF	☐ Issue cost code for tracking of expenses. ☐ Notify insurance representatives as warranted. ☐ Track expenditures and provide audit function as needed.
CRISIS MANAGER	☐ Activate BST as needed to support operation. ☐ Coordinate with the Incident Commander to mobilize backup resources. ☐ Activate the Anchorage Crisis Center to provide information distr bution support. ☐ Coordinate Government and Public Affairs notification and information effort.
WELL CONTROL OPERATION INCIDENT COMMANDER	☐ Determine if incident requires well control specialist, and if so, contact the organizations. ☐ Contact Incident Commander to initiate relief well planning.
DEPUTY OPERATIONS SECTION CHIEF OR SOURCE BRANCH DIRECTOR	☐ Identify well control options based on circumstances of incident. ☐ Notify rig contractors and coordinate activities. ☐ Implement relief well planning process. ☐ Implement logistics plan to provide well controller’s support.

FIGURE 1-1: IMMEDIATE SPILL NOTIFICATIONS AND REPORTING

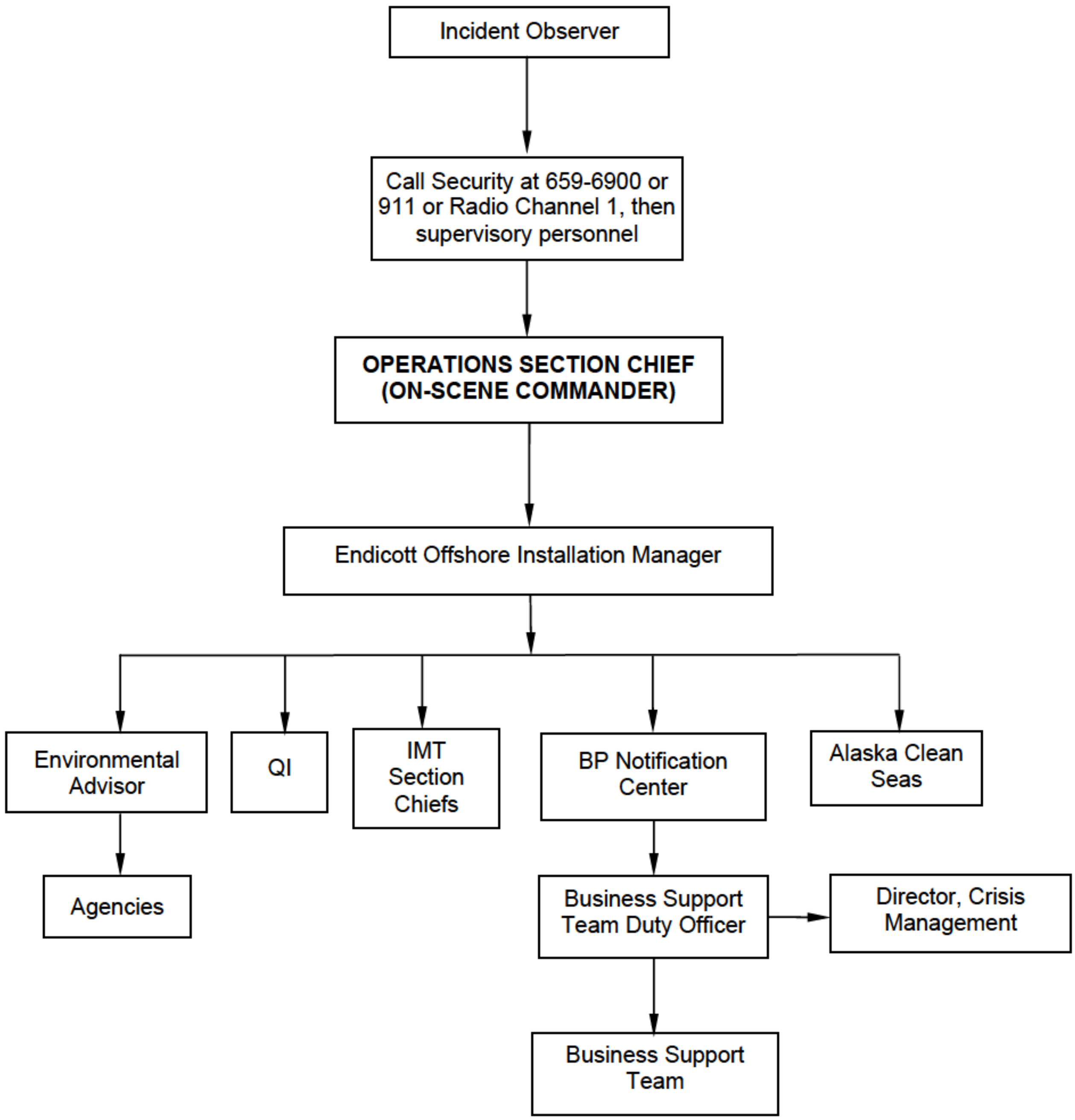
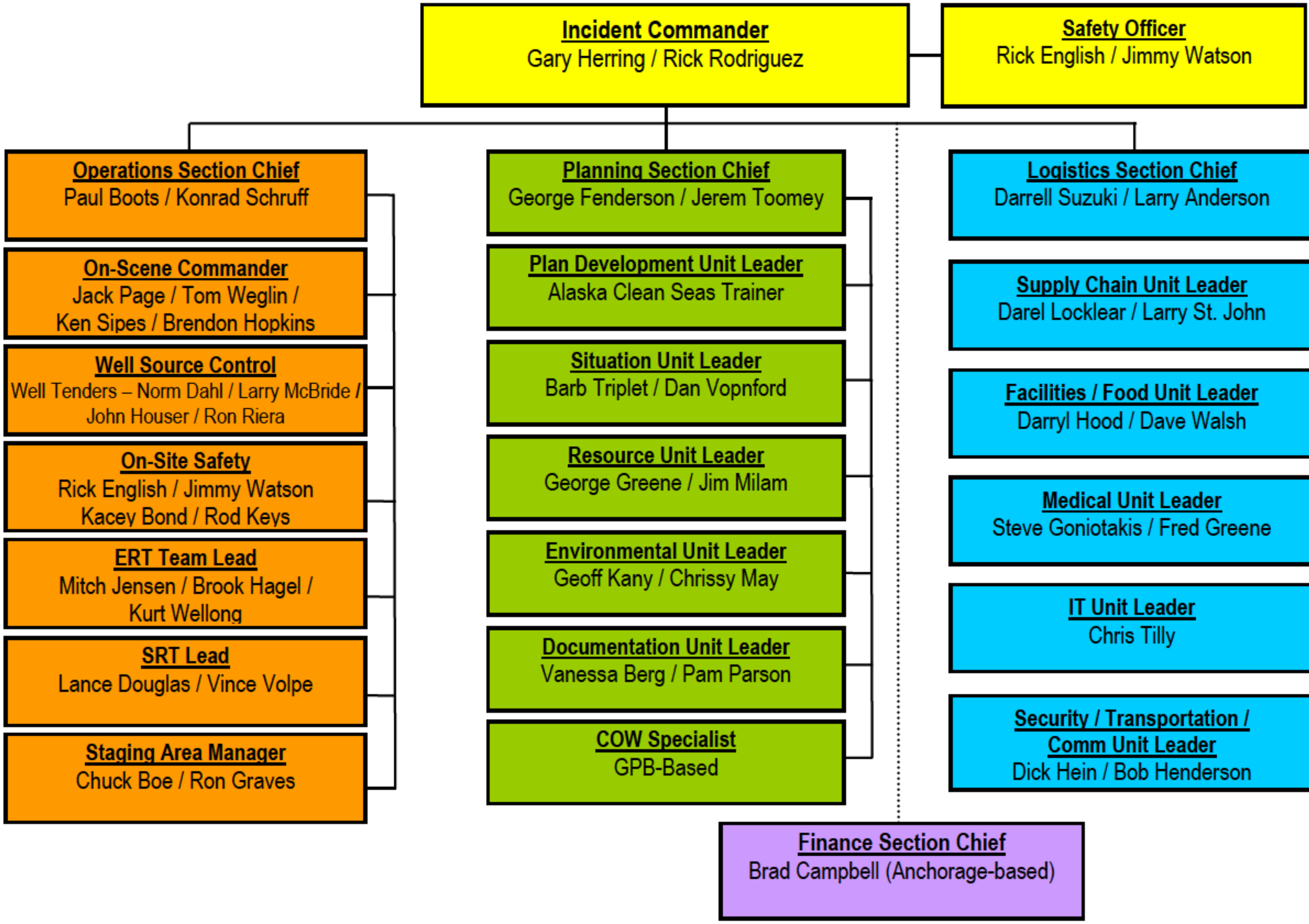


FIGURE 1-2: ENDICOTT INCIDENT MANAGEMENT TEAM



The IMT is activated by dispatch via the Harmony radio system at the direction of the Incident Commander.

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TABLE 1-2: BPXA CONTACT LIST

POSITION	NAME	TELEPHONE
VP Operations	Bruce Williams	(907) 564-4632
Environmental Team Lead (North Slope)	Tom Barrett / Chuck Wheat	(907) 659-5196
ENDICOTT		
Endicott OIM / Qualified Individual	Rick Rodriguez / Gary Herring	(907) 659-6555
Endicott OTL / Alternate Qualified Individual	Paul Boots / Konrad Schruff	(907) 659-6527
Environmental Advisor North	Geoff Kany / Chrissy May	(907) 659-6810
ACS Environmental Tech. – Endicott	Vince Volpe / Lance Douglas	(907) 659-6541
MILNE POINT UNIT (MPU)		
MPU OSM / Qualified Individual	Kenton Schoch / Wayne Hauger	(907) 670-3323
MPU Field OTL / Alt. Qualified Individual	Mark O'Malley / Rob Handy	(907) 670-3330
MPU Facility O&M TL / Alt. Qualified Individual	Gregg Alexander / Richard Knox	(907) 670-3331
Environmental Advisor MPU	Stephan Gogosha / Deb Heebner	(907) 670-3382
ACS Environmental Tech – MPU	Rob Murray / Neil Hermon	(907) 670-3473
NORTHSTAR		
Northstar OIM / Qualified Individual	JoDee Johnson / Jerry Sharp	(907) 670-3576
Alt. Qualified Individual (GPB QI)	Adrian McCaa / Shawn Croghan	(907) 659-4490
Environmental Advisor North	Geoff Kany / Chrissy May	(907) 659-6810
ACS Environmental Tech – Northstar	Philip Hubbard / Greg Guild	(907) 670-3508
GREATER PRUDHOE BAY (GPB)		
Campaign Maint. OSM / Qualified Individual	Adrian McCaa / Shawn Croghan	(907) 659-4490
Inspection Exec. TL / Alt. Qualified Individual	Randy Selman / Randy Sulte	(907) 659-8185
Environmental Advisor West	Bill Fletcher / Steve McKendrick	(907) 649-4789
Environmental Advisor East	Mike Villanova / Eric Boyette	(907) 659-5999
Environmental Advisor Central	Patrick Conway / Alex Reyes	(907) 659-5893
Environmental Advisor – Functions	Beth Sharp / TBD	(907) 659-4145
ACS Environmental Spill Technician – West	Fred Chace / Vic Richart	(907) 659-4159
ACS Environmental Spill Technician – East	Cory Settle / Tommy Cumming	(907) 659-5800
WELL CONTROL SPECIALISTS Boots and Coots Services	(800) BLOWOUT / (800) 256-9688 (281) 931-8884	
ALASKA CLEAN SEAS, OSRO Prudhoe Bay Office, Pouch 340022 Prudhoe Bay, Alaska 99734	Ron Hocking / Fred McAdams, Operations Mgr.	(907) 659-2405
BP Notification Center (Naperville)		(800) 321-8642
The numbers below are 24-hour spill reporting numbers. Qualified Individuals can be reached via these and/or the numbers above.		
Endicott		(907) 659-2222
Milne Point Unit		(907) 670-3300
Northstar		(907) 670-3515
Greater Prudhoe Bay		(907) 659-5700
O&M – Operations and Maintenance OIM – Offshore Installation Manager OSM – Onshore Site Manager	OSRO – Oil Spill Removal Organization OTL – Operations Team Lead TBD – To be determined	TL – Team Lead

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

1.2.1 INTERNAL NOTIFICATION PROCEDURES

It is BPXA policy for employees and contractors to report spills of oil or hazardous substances on BPXA leases to a BPXA representative, regardless of size. See Table 1-1, Immediate Response Checklist. The Operations Section Chief or designee ensures that safety is considered and that internal notifications are made.

1.2.2 EXTERNAL NOTIFICATION PROCEDURES

The Environmental Advisor notifies regulatory agencies per the "BPXA North Slope Event Reporting, Clean-up, and Disposal Procedure." Agency notification requirements for oil spills are listed in Table 1-3. See Figure 1-3, North Slope Spill Report Form.

1.2.3 QUALIFIED INDIVIDUAL

In the event of a spill requiring notification of the National Response Center, the Environmental Advisor or designee ensures the designated Qualified Individual (QI) is notified and is able to respond. In the event the primary QI is unavailable, the alternate QI will be contacted to respond. QIs are listed in Table 1-2.

The prerequisites for designation of a QI, as defined in 33 United States Code U.S.C. 1321(c)(4), are:

1. Available on a 24-hour basis,
2. Speak English fluently,
3. Located in the United States,
4. Trained as a Qualified and Alternate Qualified Individual under the response plan, and
5. Familiar with the emergency response plan and how to carry it out.

The QI must be trained and authorized to carry out the following responsibilities:

1. Activate and engage in contracting oil spill removal organization(s) and other response-related resources,
2. Act as a liaison with the Federal On-Scene Coordinator, and
3. Acquire funds to carry out response activities.

The QI and alternate QI are not responsible for:

1. The adequacy of the response plan prepared by the owner/operator, and
2. Acquiring funds for response resources beyond the full authority as designated by the owner/operator.

The QI or the QI's designee communicates to appropriate federal officials and response personnel if there is an oil spill requiring those communications [30 Code of Federal Regulations (CFR) 254.53(a)(2)]. Many spill response duties are delegated to members of an IMT]. The immediate duties are listed in Table 1-1.

1.2.4 WRITTEN REPORTING REQUIREMENTS

Immediate reports are made to the National Response Center (NRC) and other agencies verbally, and contain the information sought on the NRC online reporting report (to the extent known at the time of initial notification).

Depending upon the type and amount of the release, individual government agencies have written reporting requirements. See Table 1-3.

Written reports include the following:

- Date and time of discharge;
- Location of discharge;
- Name of facility, vessel or pipeline;
- Weather conditions on scene;
- 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, vessel or pipeline;
- 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.

TABLE 1-3: AGENCY REPORTING REQUIREMENTS FOR OIL SPILLS

AGENCY	LOCATION / RECEIVING ENVIRONMENT	SPILL SIZE	VERBAL REPORT	PHONE NUMBER	ALASKA CONTACT	WRITTEN REPORT
National Response Center (NRC) Notifies federal agencies as applicable. See specific federal agency below for guidance on reportable spill size.	Off pad to water or tundra	Any	Immediately	(800) 424-8802 (24 hr)	--	Not required – form is completed during phone notification process.
	To ice pad, ice road, or snow-covered tundra from an improperly functioning vessel/vehicle engine[1]	Any	Immediately			
U.S. Department of Transportation (DOT)	From a DOT-regulated pipeline and spill is **not** in or threatening navigable waters	≥5 gallons, resulting from an accident	Immediately[2]	(800) 424-8802	NRC and State Office of Pipeline Safety (Note: NRC notifies federal agencies)	Required within 30 days on DOT Form 7000-l (see form for details).
		≥210 gallons, resulting from pipeline maintenance activity[3]	Monthly written report			
	From a DOT-regulated pipeline and spill is in or threatening navigable waters	Any	Immediately	(800) 424-8802		Not required- form is completed during phone notification process

[1] Oil spills from "properly functioning vessel" engines are not reportable to the NRC (exempt by 40 CFR 110.5). "Vessel" is defined as any artificial contrivance used or capable of being used as a means of transportation on water [33 U.S.C. §1311(a)(3)]. This includes trucks, rolling stock, and exploratory vehicles traveling on frozen tundra, but not equipment like light plants. Equipment used for traveling on ice roads, including vehicles, construction machinery, water trucks, and Rolligons, will be considered a "vessel" by EPA. "Improperly functioning" refers to mechanical problems such as a broken line or hose.

[2] The operator shall give verbal notice if the release:

- Caused a death or personal injury requiring hospitalization;
- Resulted in either a fire or explosion not intentionally set by the operator;
- Caused estimated property damage, including cost of cleanup and recovery, value of lost product, and damage to the property of the operator and/or others exceeding $50,000;
- Resulted in pollution of any stream, river, lake, reservoir, or other similar body of water that violated applicable water quality standards, caused a discoloration of the surface of the water or adjoining shoreline, or deposited a sludge or emulsion beneath the surface of the water or upon adjoining shorelines; and
- If, in the operator's judgment, it was significant even though it did not meet the criteria.

[3] No report is required for a release less than 5 barrels resulting from a pipeline maintenance activity if the release is:

- Not otherwise reportable;
- Did not result in pollution of any stream, river, lake, reservoir, or other similar body of water that violated applicable water quality standards, caused a discoloration of the surface of the water or adjoining shoreline, or deposited a sludge or emulsion beneath the surface of the water or upon adjoining shorelines; and
- Confined to company property or pipeline right-of-way and cleaned up promptly.

TABLE 1-3 (CONTINUED): AGENCY REPORTING REQUIREMENTS FOR OIL SPILLS

AGENCY	LOCATION / RECEIVING ENVIRONMENT	SPILL SIZE	VERBAL REPORT	PHONE NUMBER	ALASKA CONTACT	WRITTEN REPORT
State Pipeline Coordinator's Office (Joint Pipeline Office) Anchorage, Alaska	Pipelines administered by the State Pipeline Coordinator's Office (SPCO) authorized under AS 38.35	Any	Immediately	(907) 257-1330 (direct) (907) 257-1300 (office) (907) 272-0690 (FAX)	Mike Thompson (State Pipeline Coordinator)	Not required.
U.S. Department of the Interior, Bureau of Safety and Environmental Enforcement (BSEE) Applicable to Endicott, Northstar, and PM2	Marine waters	>42 gallons (1 barrel)	Immediately	(907) 334-5300 (24-hr) (907) 334-5302 (FAX)	Christy Bohl	Required within 15 days after spill is contained.
	All losses of well control	Any	Immediately			Required within 15 calendar days of incident
Alaska Department of Environmental Conservation (ADEC)/Alaska Department of Natural Resources (ADNR)[4] ADNR has the same spill reporting requirements as ADEC[4]	Off pad to water or tundra	Any	Immediately (within 30 minutes)	ADEC (907) 451-2121 (907) 451-2362 (FAX) or Alaska State Troopers (800) 478-9300 (M-F after 5, Sat, Sun)	ADEC Tom DeRuyter ADEC fax number or Alaska State Troopers After-hours spills with immediate notification requirements	Required within 15 days after spill containment and cleanup are completed, or if no cleanup occurs, within 15 days after discharge or release.
	On gravel pad, gravel road, ice pad, ice road, or snow-covered tundra (Note: spills to snow, ice roads, and ice pads that do not penetrate to surface water or tundra are treated as spills to gravel pads)	<1 gallon	None			
		1 to 10 gallons	Monthly written report			
		>10 to 55 gallons	Within 48 hours			
		>55 gallons	Immediately			
	Impermeable secondary containment areas or structures	>55 gallons	Within 48 hours	ADNR (907) 451-2678 (907) 451-2751 (FAX)	ADNR Spill Report Number ADNR fax number	

[4] The low concentrations and volumes of scale inh bitors, corrosion inhibitors, or biocides that are contained in and being used for their intended purpose in brines, seawater, produced water, drilling fluids, or crude oil do not trigger a spill reporting requirement. Rather, the requirement to notify ADEC of the release shall consider the parent material without the inclusion of these substances. As with all spill reports, all materials released must be included in the report whether or not they would, on an individual basis, trigger a reporting requirement to the State.

TABLE 1-3 (CONTINUED): AGENCY REPORTING REQUIREMENTS FOR OIL SPILLS

AGENCY	LOCATION / RECEIVING ENVIRONMENT	SPILL SIZE	VERBAL REPORT	PHONE NUMBER	ALASKA CONTACT	WRITTEN REPORT
Alaska Oil and Gas Conservation Commission (AOGCC)	From wells or involving any crude loss Uncontrolled releases	Any >10 barrels or resulting in the shutdown of operations at production facilities	Immediately	(907) 279-1433 (24 hr) (907) 276-7542 (FAX) (907) 659-3607 (pager) (907) 659-2717 (FAX)	Dan Seamount John Norman Cathy Foerster	Required within 5 days of loss and Final report within 30 days
North Slope Borough	Off pad to water or tundra	Any	Immediately	(907) 852-0440	Planning Department After hours* Thomas Simmonds III (907) 306-9285 Gordon Matumeak (907) 878-2194 Charles Russell (907) 306-5209 Tony Cabinboy (907) 878-2193 Roy Varner	Copy of reports submitted as requested.
	On gravel pad, gravel road, ice pad, ice road, or snow-covered tundra	>55 gallons	Immediately			
	Impermeable secondary containment areas or structures	>55 gallons	Immediately			

* North Slope Borough after hours reporting is a courtesy.

FIGURE 1-3: NORTH SLOPE SPILL REPORT FORM

Company:	Cause:
Contact:	
Phone Number:	
Spill Date:	
Spill Time:	Cleanup:
Location:	
Material Spilled:	
Amount:	
Area Affected:	Disposal:
Contained?	
Tundra or water affected?	
Weather Conditions? (temp, wind speed, skies)	
Comments:	
Time BPXA Person-in-Charge of Facility (Environmental Advisor) first obtained Knowledge of the Spill:	

Agency	Phone	Date	Time	Reported By	Reported To	Report Number
NRC (notifies EPA/ USCG/ USDOT/ BSEE) **(+ GPB see note below)** For DOT PL events, notify the BP DOT PL TL For BSEE events, notify Regional Supervisor.	(800) 424-8802					
ADEC After Hours (STATE TROOPERS)	(800) 478-9300					
ADEC During Business Hours	(907) 451-2121					
ADEC (sewage)	(877) 569-4114					
ADFG	(907) 459-7289					
ADNR	(907) 451-2678					
AOGCC (Anchorage)	(907) 279-1433					
AOGCC (Slope)	(907) 659-3607					
NSB During Business Hours	(907) 852-0440					
NSB After Hours	(907) 878-2193					
SPCO	(907) 257-1300					
BSEE (Notify for oil spills ≥1 bbl)	(907) 334-5300					
NPDES Hotline	(206) 553-1846					

Note FOR GPB ONLY: For spills reported to NRC and >10 gallons to water or tundra, or >55 gallons to gravel pad (includes snow, ice roads and ice pads), Send an email or fax to Robbie Hedeen at EPA within 5 days (hedeen.roberta@epa.gov, fax 206-553-8509). Done on Date: Time:

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

The BP Control of Work Requirements were developed to reduce the number and frequency of injuries and serious incidents that occur in the workplace. The requirements ensure that there is a formal approach to managing work risks. The requirements are a procedural form of control, consisting of 12 elements supported by mandatory requirements. They cover the means of safely controlling construction, maintenance, demolition, remediation, operating tasks and similar work activities and apply to BP employees and every employee of any other company engaged to perform work on BPXA premises. The requirements are detailed in the *2010 BP Team Alaska Safety Handbook*.

The steps to develop an incident-specific safety plan are outlined in the ACS *Technical Manual*, Tactics S-1 through S-6 and the *2010 BP Team Alaska Safety Handbook.* The ACS *Technical Manual*, Tactics S-1 through S-6, incorporated here by reference, discusses site entry procedures, site safety plan development, and personnel protection procedures. The *Alaska Safety Handbook* is distributed to North Slope employees and contractors.

The BPXA well plan prepared for each drilling operation conducted on the North Slope is designed to ensure drilling activities are performed in a safe and environmentally sound manner. Each plan identifies the procedures, systems, and equipment employed in drilling; uses the best technical information available concerning subsurface formation characteristics and pressures; and provides information critical to the success and safety of the drilling program.

Emergency response procedures are in place for evacuation in and around the facility in the event of a discharge or release of stored materials. Hazards posed by discharged materials and a discussion of discharge flow direction, prevailing wind direction and speed, receiving environment, and emergency response actions are presented in the response scenarios in Part 1.

Emergency procedures are on the BPXA intranet and are available to employees and contractors. The procedures cover alarm and notification systems, primary and alternate evacuation routes, designated safe areas, roll-call procedures, and initial identification and treatment of injured personnel, including transportation to medical facilities.

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

The communications plan is compatible with the communications equipment available through BPXA's Anchorage office, BPXA's North Slope facilities and ACS. Radio equipment on site is listed in Table 1-4.

TABLE 1-4: ENDICOTT RADIO EQUIPMENT

EQUIPMENT	• Very high frequency (VHF) oil spill repeater • Transmission line with connectors • VHF antenna • Marine private coast station • VHF hand-held radios (10 each) • Satellite phones
FREQUENCIES	**VHF Oil Spill (OS-41)** • Repeater transmit: 159.585 mega hertz (MHz) • Repeater receive: 161.235 MHz • Private line code: 107.2 hertz (Hz) **VHF Private Coast (OS-71)** • Transmit and receive on 156.500 MHz (Marine Channel 10)

The VHF repeater provides a direct tie-in to the ACS communications system. With such repeaters installed across the North Slope, coverage is provided from Alpine to Badami. The range of each fixed repeater is approximately 30 to 50 miles, depending on topography. ACS solar-powered portable repeaters can also be deployed at the time of a spill. ACS will provide the repeater, coast station, antennas, hand-held radios, and backboarded mobiles when necessary in an emergency.

A detailed explanation of oil spill communications on the North Slope is provided in the ACS *Technical Manual,* Tactic L-5, incorporated here by reference.

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

In this plan, mobilization means readying for travel. Deployment means readying for use at the site. Travel time is the period between mobilization and deployment.

Initial spill response transportation relies on the BPXA daily operations infrastructure. The extensive transportation infrastructure of personnel and equipment can support a small response and be enhanced for a major spill. Transportation options provide alternative methods in adverse weather. Options are summarized in Table 1-5.

TABLE 1-5: SEASONAL TRANSPORTATION OPTIONS

MODES OF TRANSPORTATION	SEASONS		
	SUMMER	WINTER	BREAK-UP/ FREEZE-UP
Vessels	X	Not applicable	Partial
Helicopters	X	X	X
Fixed-wing aircraft at Badami	X	X	X
Vehicles	X	X	X
Heavy all-terrain vehicles (ATVs)/Rolligon	X	X	X

The ACS *Technical Manual* (Tactics L-3, L-4, and L-6) provides detailed information on transportation procedures and is incorporated here by reference.

Endicott is tied into the Prudhoe Bay road system by the Endicott causeway and road. Endicott and the Badami pipeline are accessible by helicopter if necessary. Generally, year-round air access to the Badami field area is available. The Badami airstrip accommodates Hercules aircraft, plus smaller aircraft such as Twin Otters and helicopters. Air operations can be limited by weather conditions. Details are provided in the ACS *Technical Manual*, Tactic L-4.

BPXA can obtain aircraft during emergencies from BPXA/ConocoPhillips Shared Services Aviation and Alyeska Pipeline Service Company. Shared Services Aviation has a Twin Otter and a CASA, and Alyeska Pipeline Service Company has a Bell 206-L helicopter on contract that would be made available to BPXA upon request. The helicopter is based at Pump Station 4.

Land-based access to the Badami pipeline is possible when tundra travel is authorized by the State of Alaska and the North Slope Borough. ACS holds an emergency tundra travel permit which can be used for tundra travel throughout the year. Tundra travel is not permitted during break-up. Summer tundra travel vehicles such as a CATCO RD-105 can typically transport loads up to 45,000 pounds. Winter tundra travel vehicles such as a CATCO tractor trailer can typically transport loads up to 60,000 pounds. In winter, the option of using tracked vehicles is also available. The CATCO vehicles are currently available and are in common use on the North Slope. Rolligons are also available from contractors based in Deadhorse. Equipment and personnel can travel about 10 miles per hour (mph) over tundra. Travel from the Endicott road to Badami in mid-winter would take approximately 2 to 2.5 hours depending on conditions.

Marine vessel access to Endicott is available from July through September. Vessel travel times are presented in the ACS *Technical Manual*, Tactic L-3. BPXA and ACS have contracts in place with the major North Slope marine contractors.

ACS is the primary response action contractor for BPXA. The 24-hour phone number for ACS is listed in Table 1-2.

Section 1.1 describes immediate response and notification actions, including notification of ACS. While ACS is mobilizing personnel and equipment to the spill site, on-site BPXA and ACS personnel will determine safety procedures, notify government agencies and BPXA personnel, and proceed with source-control measures. Off-site BPXA personnel may be consulted as necessary.

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

1.6.1 QUALIFIER STATEMENT

Scenarios are developed in accordance with 18 Alaska Administrative Code (AAC) 75.425(e)(1)(F) and (I) and 18 AAC 75.445(d). They describe equipment, personnel, and strategies that could be used to respond to an oil spill. The scenarios describe oil spill recovery by 100 percent mechanical means, as required by 18 AAC 75.425(e)(1)(F)(vii).

The scenarios are for illustration only and are not performance standards or guarantees of performance. Actual responses in an oil spill emergency depend on personnel safety considerations, weather and other environmental conditions, agency permits and priorities, and other factors. In an accident, considerations to ensure the safety of personnel will be given highest priority. The scenarios assume conditions only for the purposes of describing general procedures, strategies, tactics, and selected operational capabilities. The scenarios assume the agency On-Scene Coordinators and other agency officials will immediately grant required permits.

Although equipment is specified in the scenarios, it may be replaced by functionally similar equipment in the future. The response timelines are for illustration only. They do not limit the discretion of the people in charge of the spill response to select a specific sequence or take the time they deem necessary for an effective response without jeopardizing safety.

Some scenarios simulate heavy equipment operations, e.g., truck drivers and front-end loader operators. Staff in the equipment operator category typically operate their equipment on a regular schedule on the North Slope unrelated to spill responses and are not members of the North Slope Spill Response Team (NSSRT).

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.

The response strategies illustrate specific response measures to reduce the risk, magnitude or environmental consequences of an oil spill during periods when mechanical spill response is limited, as described in 18 AAC 75.445(f) and 18 AAC 75.425(e)(3)(D). Section 3.4, Realistic Maximum Operating Limitations, and Section 3.7, Non-Mechanical Response Information, describe the capability of BPXA and ACS to effectively remove spilled oil by means of in situ burning in a range of ice conditions including during spring break-up and fall freeze-up.

1.6.2 WASTE DISPOSAL APPROVAL

The method of disposal for oil and contaminated materials from oil spill recovery operations first must be approved by state and federal agencies before implementation. At the time of the spill, the Operations Section Chief, in consultation with the Environmental Unit Leader, will determine a reuse, recycle, or disposal method best suited to the condition of the oil, the degree of contamination of recovered debris, and the logistics involved. See Tactics D-1 through D-5 in the ACS *Technical Manual*.

When an IMT is not involved, spills of crude oil and exempt hazardous substances (refined fuels, lube and hydraulic oils, produced waters, seawater, source water, glycol, and drilling muds) of 200 gallons or less to gravel pads, roads, ice roads, or ice pads can automatically invoke the use of pre-approved permitted storage and disposal facilities. For spills above the threshold level, or to other receiving environments, approval for storage and disposal will be obtained from the State On-Scene Coordinator before material is removed to those facilities. The approval can be in the form of a verbal communication during initial spill notification.

An initial determination of exempt, hazardous, or non-hazardous must be made for classification of the waste. This classification must be made on a case-by-case basis. The Environmental Unit Leader will provide assistance in determining the classification should the status of the waste material be in question. The applicable guidelines are listed below.

- Spills from common carrier transportation pipelines are non-exempt, and it must be determined whether the material to be disposed of is hazardous,
- Spilled material that comes out of a well, either during drilling or workover operations, is exempt. Spilled material that did not come out of a well is non-exempt, and it must be determined whether the material to be disposed of is hazardous, and
- Spills of non-exempt fluids that occur during filling a tank (e.g., vehicle, storage, etc.) are non-exempt, even though they may occur on a well pad, and it must be determined whether the material to be disposed of is hazardous.

The preferred management option for recovered oil and diesel is to recycle it back into the production stream. If the material is not suitable for recycling, it will be determined whether it is hazardous. If hazardous, it will be placed in drums and stored on site until it is shipped to an approved hazardous waste treatment, storage, or disposal facility. The Environmental Advisor will determine the appropriate management method.

Guidelines for handling and managing oil and contaminated materials from oil spill recovery operations or for oily waste from normal operations are found in the “Alaska Waste Disposal and Reuse Guide.”

1.6.3 RESPONSE SCENARIOS AND STRATEGIES

The Response Planning Standard (RPS) scenarios presented in this section show that the plan meets the RPS volumes described in Part 5.

- Scenario 1: Endicott Wastewater Tank Rupture During Summer
- Scenario 2: Well Blowout Under Typical Summer Conditions
- Scenario 3: Well Blowout Under Typical Winter Conditions
- Scenario 4: Crude Oil Transmission Pipeline Release
- Response Strategy #1: Endicott Diesel Tank Rupture During Summer
- Response Strategy #2: Well Blowout During Typical Broken Ice Conditions
- Response Strategy #3: Badami Crude Oil Transmission Pipeline Release During Summer

SCENARIO 1

ENDICOTT WASTEWATER TANK RUPTURE DURING SUMMER

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TABLE 1-6: WASTEWATER TANK RUPTURE SCENARIO CONDITIONS

PARAMETER	PARAMETER CONDITIONS
Spill Location	Endicott, Main Production Island (MPI)
Date	August 1, 10:00 am
Source of Spill	Wastewater storage tank, T-E3-1802
Cause of Spill	Tank failure
Duration	Instantaneous
Quantity of Spill	Initial RPS volume is 4,912 barrels (bbl), of which 4,666 bbl is released to the gravel pad (as the adjusted RPS volume). No oil reaches open water. Refer to Part 5 for detailed explanation of RPS.
Type of Spilled Oil	Wastewater (produced water and water-oil mixtures)
Weather	Overcast, 48 degrees Fahrenheit (F)
Wind Direction and Speed	Wind from the east-northeast at 15 knots
Spill Trajectory	For the purposes of this scenario, the tank is damaged and approximately 4,666 bbl of produced water flows onto the pad and area surrounding the tank. No oil reaches open water. See Figure 1-4.

TABLE 1-7: WASTEWATER TANK RUPTURE RESPONSE SCENARIO

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(i) Stopping Discharge at Source	To prevent additional wastewater from entering the tank, the loading line is blocked and the pump is tagged and locked out. Notification procedures begin, along with SRT mobilization. A staging area and field command post are established. Within the first few hours of the spill, Production Supervisors prepare a team to perform repairs to the tank. The team stabilizes the weakened area of the secondary containment with gravel to prevent further escape of fluids.	Not applicable
(ii) Preventing or Controlling Fire Hazards	Because a large fraction of the released fluids is water, the threat of fire or explosion is not expected to be significant. Nonetheless, the Fire Chief is on the scene with equipment and personnel to suppress the threat of an explosion. Throughout the first few hours of the spill, the Fire Chief verifies that sources of ignition are shut down or removed from the area. After declaring the area clear, the Site Safety Officer (SSO) begins to prepare a site safety plan (ICS Form 201-5) including PPE requirements. The first draft of the site safety plan focuses on the delineation, containment, and source control teams. It quickly evolves to include spill recovery teams. Access to the spill site is carefully controlled and the scene is secured by Security. Monitoring protocol is established by the SSO for all work areas to ensure personnel protection.	S-1 through S-6
(iv) Surveillance and Tracking of Oil; Forecasting Shoreline Contact Points	Once safety zones and a decontamination unit have been set up by Hour 4, the oiled area is delineated. The extent of oil on the pad is delineated with lathe and/or hand-held global positioning systems (GPS) units.	T-1, T-2, T-7
(v) Protection of Environmentally Sensitive Areas and Areas of Public Concern	No priority protection sites lie in the spill trajectory.	See Map 67
(vi) Spill Containment and Control Actions	A staging area and field command post are set up at the MPI facility. Gravel berms are constructed to ensure that the wastewater remains trapped in the immediate areas and depressions. On Day 2, ground disturbance permits have been acquired. Containment crews excavate small trenches to aid recovery operations.	L-2 C-4

TABLE 1-7 (CONTINUED): WASTEWATER TANK RUPTURE RESPONSE SCENARIO

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(vii) Spill Recovery Procedures	On Day 1, vacuum trucks begin to recover liquids. One crew recovers fluids from the damaged tank, and the remainder recovers fluids from the pad. On Day 2, containment crews excavate small trenches. Vacuum truck crews use the trenches to increase recovery. Once the standing wastewater is removed from the depression areas and the trenches are excavated, the liquid recovery task forces use warm water to flush the area to float the remaining wastewater for further recovery. The vacuum trucks recover fluids from some areas with Manta Ray skimmers. After liquids are removed, grid sampling indicates the depth of gravel penetration, and a crew excavates the contaminated gravel. The contaminated gravel inside the containment area is hand-shoveled off the liner and transported and stored for later handling.	R-27, R-6 R-7 R-4 R-6 R-26
(viii) Lightering Procedures	Not applicable	Not applicable
(ix) Transfer and Storage of Recovered Oil/Water; Volume Estimating Procedure	Vacuum trucks offload recovered oil directly to the processing facilities. Liquids processed are manifested at the vacuum trucks offload point.	R-6
(x) Plans, Procedures, and Locations for Temporary Storage and Disposal	Oily liquids are taken to Flow Station 2 for enhanced oil recovery (EOR). Non-liquid oily wastes are classified and disposed of according to classification. Non-oily wastes are classified and disposed of accordingly. Oiled gravel is excavated and stockpiled at Endicott's Class II cell pit. Stockpiled gravel will be disposed of according to the waste management plan.	D-1 D-2 D-3 D-4
(xi) Wildlife Protection Plan	The wildlife protection strategy is implemented. Wildlife hazing teams are deployed.	W-1 W-2B
(xii) Shoreline Cleanup Plan	No shorelines are impacted.	Not applicable

TABLE 1-8: WASTEWATER TANK RUPTURE OIL RECOVERY CAPABILITY

A	B	C	D	E	F	G
SPILL RECOVERY TACTIC, ACS TECHNICAL MANUAL TACTICS DESCRIPTION	**NUMBER OF RECOVERY SYSTEMS**	**RECOVERY SYSTEM**	**OIL RECOVERY RATE CAPCITY PER UNIT (BOPH OR CUBIC YARDS [YD^3] PER DAY)**	**MOBILIZATION, DEPLOYMENT, AND TRANSIT TIME TO SITE (HOURS)**	**OPERATING TIME (HOURS PER 24-HOUR SHIFT)**	**OIL RECOVERY CAPACITY (BOPD) OR (YD^3/DAY) B x D x F**
Liquid Recovery (R-27, R-6)	4	Vacuum Truck	69[1]	4	20	5,520 bopd
Liquid Recovery (R-6)	2	Vacuum Truck with Manta Ray skimmer	16[2]	4	20	640 bopd
Oiled Gravel Recovery (R-26)	2	Backhoe, Front-end loader, Dump Truck	14[3]	24	20	560 yd^3/day

bopd = barrels of oil per day

boph = barrels of oil per hour

yd^3 = cubic yards

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[1] Vacuum truck recovery calculation: Time = (miles to disposal * 2 trips / 35mph + 2(Tc/Sr),
Time = (24 miles from site to Flow Station 2 * 2 trips / 35 mph) + 2(300 bbl / 200 boph) = 4.37 hours, where Tc = Vacuum Truck Capacity = 300 bbl, Sr = Suction Rate = 200 boph
Oil recovery rate (ORR) = vacuum truck capacity/time, ORR = 300 bbl/4.37 hours = 69 boph.

[2] Vacuum truck recovery calculation (when using Manta Ray skimmer): Time = (miles to disposal * 2 trips / 35mph + 2(Tc/Sr),
Time = (24 miles from site to Flow Station 2 * 2 trips / 35 mph) + 2(300 bbl / 34 boph) = 19 hours, where Tc = Vacuum Truck Capacity = 300 bbl, Sr = Suction Rate = 34 boph
Oil recovery rate (ORR) = vacuum truck capacity/time, ORR = 300 bbl / 19 hours = 16 boph.

[3] Dump recovery calculation for gravel: Tc/(Lt+Tt+Ut) = 20 yd^3 / [0.25 hour + (20 miles from Endicott to GPB G & I * 2 trips / 35 mph) + 0.08 hour] = 14 yd^3/hour, where,

Tc = Truck Capacity = 20 yd^3

Lt = Load Time = 0.25 hour

Tt = Travel Time = 20 miles from Endicott to GPB G & I * 2 trips at 35 mph

Ut = Unload Time = 0.08 hour

TABLE 1-9: MAJOR OIL RECOVERY EQUIPMENT EQUIVALENTS

RECOVERY TACTIC	EQUIPMENT PER TACTICAL UNIT
Containment (C-4)	1 x Backhoe 1 x skid steer
Liquid Recovery (R-6)	6 x Vacuum Trucks 2 Manta Ray skimmer
Flushing (R-4) (Works in coordination with R-6 teams)	1 x water truck 1 x 2-inch trash pump various lengths discharge and suction hose
Oiled Gravel Recovery (R-26)	2 x Backhoe 2 x Front-end loader 2 x Dump Truck

TABLE 1-10: STAFFING TO OPERATE OIL RECOVERY EQUIPMENT

LABOR CATEGORY	TACTIC	TACTIC DESCRIPTION	DAY 1 STAFF PER SHIFT	STAFF PER SHIFT TO SUSTAIN OPERATIONS
Team Lead	C-4	Containment	1	1
	R-6	Liquid Recovery	1	1
	R-4	Flushing	0	1
	R-26	Oiled Gravel Recovery	0	1
Skilled Technician	R-4	Flushing	0	3
General Laborer	C-4	Containment	2	2
	R-6	Liquid Recovery	6	6
Equipment Operator	C-4	Containment	2	2
	R-4	Flushing	0	1
	R-6	Liquid Recovery	6	6
	R-26	Oiled Gravel Recovery	0	6
		Total:	**18**	**30**

Note: Equipment operators are not necessarily members of the North Slope SRT.

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SCENARIO 2

WELL BLOWOUT DURING TYPICAL SUMMER CONDITIONS

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TABLE 1-11: SCENARIO CONDITIONS WELL BLOWOUT UNDER TYPICAL SUMMER CONDITIONS

PARAMETER	PARAMETER CONDITIONS
Spill Location	Satellite Drilling Island (SDI) well 4-10A/L28.
Date and Time of Spill	July 15, 6:00 am
Cause of Spill	Uncontrolled well blowout
Duration	15 days
Quantity of Spill	RPS volume = 857 bopd x 15 days = 12,855 bbl
Type of Oil Spilled	Alaska North Slope crude oil
Weather	Partly cloudy, 40°F
Average Wind Speed and Predominant Wind Direction	During summer, the average wind speed is 12 knots. The predominant wind directions were determined from the 16 cardinal compass directions that blow over 10 percent of the time. For May to October, the predominant wind directions at Endicott are from the NE, ENE and E. See Figure 1-5. The wind data were retrieved from the Nearshore Beaufort Sea Meteorological Monitoring and Data Synthesis (Veltkamp, B. and Wilcox, 2007) and a cooperative monitoring project between BPXA and Shell on Endicott's Endeavor Island. The weather data presented were collected during the summers of 2001 through 2011.
Sea Surface Current and Speed	Surface currents are wind-driven. Surface current speeds are 1.4 knots in Sagavanirktok River and 0.6 knots in Beaufort Sea.
Trajectory	The scenario location was selected per ADEC regulations [18 AAC 75.434(e)]. Well 4-10A/L28 was the highest producing well according to AOGCC's production reports from January 2010 through December 2010. Simulated oil flows from the 4-inch (inner diameter) open orifice well at the rate of 857 bopd with gas-to-oil ratio (GOR) of approximately 7,440 standard cubic feet per barrel. The discharged oil takes the form of an aerial plume extending from the well to the SW, WSW, and W with the direction of prominent winds (ACS Technical Manual Tactic T-6). The S.L. Ross model (1997) indicates that 10 percent of the discharged oil is in the form of drops so small (50 micrometers [μm] or less) that they do not fall to the ground but are held aloft by atmospheric turbulence. For response planning purposes, the oil predicted by the model to remain airborne is proportionally distr buted within the projected blowout plume footprint. Although all production wells are enclosed within facilities, the following scenario assumes an unobstructed blowout. The projected plume dimensions are approximately 2.7 miles long and 2,000 feet wide (at the widest point). See Figure 1-6. Approximately 60 percent (8,570 bbl) of the oil falls to the production pad. Approximately 80 percent of the discharged oil falls within 2,032 feet of the well. If left unrecovered for 15 days, the average thickness of the discharged oil deposited in the lagoon between SDI and the Endicott causeway is 0.4 inches and the average thickness in the delta west of the causeway is 0.002 inches.

TABLE 1-11 (CONTINUED): SCENARIO CONDITIONS
WELL BLOWOUT UNDER TYPICAL SUMMER CONDITIONS

PARAMETER	PARAMETER CONDITIONS
Trajectory **(continued)**	Over a 15 day period, the following volumes are discharged: Days 1 to 2.8: 2,418 bbl are deposited to the southwest Days 2.9 to 9.1: 5,426 bbl are deposited to the west-southwest Days 9.1 to 15: 5,011 bbl are deposited to the west After it has been deposited to the ocean surface, oil forms into windrows. Floating oil moves at the same speed as the underlying water plus three percent of the wind speed. The direction and speed of the oil can be predicted by vector addition. (See ACS *Technical Manual* Tactic T-5, incorporated by reference.) Oil falling to the pad remains on the pad, retained in gravel and accumulating in depressions. Water discharging from the Sagavanirktok River will keep the oil from the delta shoreline, deflecting it to Prudhoe Bay under the NE, ENE and E winds.

TABLE 1-12: RESPONSE STRATEGY
WELL BLOWOUT UNDER TYPICAL SUMMER CONDITIONS

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(i) Stopping Discharge at Source	The On-Site Company Representative takes the role of Initial Deputy Operations Section Chief, and notifies the Drilling Superintendent, Operations Team Lead, and the affected Alaska Drilling and Wells (ADW) Team Lead. The IMT is activated. The affected ADW Well Manager calls well control specialists to obtain guidance for source control. Production is shut down, closing in the wells at the surface and subsurface. Personnel are evacuated when control is not immediate and safety is at risk. The Operations Team Lead assumes Surface Control leadership and plans initial surface controls.	A-1, A-2, L-2 BPXA Incident Management System (IMS) Manual
(ii) Preventing or Controlling Fire Hazards	The Operations Section Chief sets up access zones and routes and firefighting operations to protect assets and workers. Throughout the first few hours of the spill, the Operations Section Chief, with the assistance of the SSO and Fire Chief, verify no ignition sources in the area. The SSO determines response workers' PPE needs and provides hot and warm zone access information. The first draft of site safety plan (ICS Form 201-5) focuses on the delineation, containment and source control teams. It quickly evolves to include spill recovery teams. Monitoring protocol is established by the SSO at work areas for personnel protection. The monitoring protocol establishes safety zones according to applicable Occupational Safety and Health Administration (OSHA) and fire hazard standards. Containment and recovery operations are conducted in accordance with site entry procedures. Recovery operations and oil field operations are disallowed downwind of the blowout well in areas where personnel may become exposed to flash fire hazard or oil particulate matter at concentrations greater than permissible exposure limits. Firewater coverage is set up by source control specialists.	S-1 through S-6
(iv) Surveillance and Tracking of Oil; Forecasting Shoreline Contact Points	By Hour 4 an aircraft is dispatched to monitor for oil. The slick is tracked by the aircraft, which records with a Forward Looking Infrared (FLIR) system. Approximately 4 hours after the aircraft has finished the survey, the infrared data is overlain on a digital map of the area, resulting in a detailed map of the spill. The system works during day or night conditions. The deployment of tracking buoys is considered. The buoys are capable of transmitting position information and other pertinent data to satellites for retransmission to Unified Command. Field data are used to periodically update the trajectory maps. National Oceanic and Atmospheric Administration (NOAA) is requested to provide trajectories based on wind speed and direction.	T-4 T-5

TABLE 1-12 (CONTINUED): : RESPONSE STRATEGY WELL BLOWOUT UNDER TYPICAL SUMMER CONDITIONS

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(v) Protection of Environmentally Sensitive Areas and Areas of Public Concern	The Environmental Unit issues an advisory with the concurrence of the State Historic Preservation Officer. The Operations Chief directs that crews avoid the cultural sites as noted by the ACS Technical Manual Map Atlas and Alaska Heritage Resource Survey data. Catalogued cultural resource sites are listed on the maps that cover their vicinity in the spill area. The Technical Manual lists are adapted from the "North Slope Subarea Plan." The Unified Command approves the activities and tactics used to protect environmentally sensitive areas and areas of public concern. Priority protection sites PS5 and PS7 are within the blowout's aerial plume. **Task Force 1: Marine Shoreline Protection** By Hour 3, crews launch vessels from West Dock and MPI. The crews deploy deflection west of the causeway. The objective is to keep oil from migrating west of the Sagavanirktok River delta. Light ocean containment boom is deployed downwind and down current of the impacted area. Deflection boom is deployed in a series to deflect oil into the deeper channel.	W-6, Map Sheet 74 W-6, Map Sheet 74 C-13
vi) Spill Containment and Control Actions **and** **(vii) Spill Recovery Procedures**	During the first shift, a BPXA Field Command Post, a decontamination unit and staging area are established along the causeway. **Support Task Forces** Support task forces set up on Shift 1. Deep water recovery operations are staged at West Dock and MPI. Shallow water recovery operations are staged at the Fire Training Grounds. Staging and decontamination areas for land recovery operations are set up at MPI and Duck Island Gravel Mine. If necessary, decontamination for marine vessels is set up at MPI. Containment and recovery crews work cross-wind or upwind of the aerial plume. All containment and control activities are conducted in accordance with ACS site entry protocols. **Task Force 2: Lagoon Area Containment** The objective is to provide containment south of the discharged oil, in the lagoon area between SDI and the causeway. Airboats towing boom are mobilized. Airboats allow the crews to get close to the site. As conditions allow, boom is placed manually. See Figure 1-7. **Task Force 3: River Containment and Control** By Hour 3, airboats carrying boom are mobilized from the EOA Fire Training Grounds and deploy containment boom at the mouth of the Sagavanirktok River. **Task Force 4: On-Pad Recovery** As conditions allow, two vacuum trucks attempt to recover pooled oil on the SDI pad. In this scenario, TF-4 is assumed to recover 4 hours per day due to limited access. Two vacuum trucks remain on the Endicott facility full-time.	C-13, C-14 C-8 R-6

TABLE 1-12 (CONTINUED): : RESPONSE STRATEGY WELL BLOWOUT UNDER TYPICAL SUMMER CONDITIONS

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(vi) Spill Containment and Control Actions (continued) **and** **(vii) Spill Recovery Procedures (continued)**	**Task Force 5: Marine Recovery** By Hour 8, marine-based recovery has commenced. As conditions allow, shallow draft workboats tow delta containment boom in a J configuration and support a Crucial C Disc 13/30 skimmer in the boom apex. As conditions allow, TF-5 employs single boom-arm skimming tactics to get closer to the plume. The recovered fluids are stored in a mini barge which holds 100 barrels, less than its 249-barrel capacity, to reduce draft and prevent grounding. The recovered oil and water is transported to a vacuum truck stationed at a fluid transfer area set up at MPI.	R-17, R-32A
	Task Force 6: Causeway Hook Boom Recovery By Hour 8, Task Force 6 deploys hook boom recovery units from the west side of the causeway. Three Crucial C Disc 13/30 skimmers and one Elastec drum skimmer, TDS-118 collect oil within the boom containment areas. At the end of Day 2, the wind shifts, allowing recovery crews better access to Little Skookum breach.	R-16
	Task Force 7: Swift Water Recovery On Day 4, crews deploy a swift water recovery system at Little Skookum breach. Crews deploy conventional deflective boom and a Harbor buster/boom system down current of the breach. A Crucial C Disc 13/30 skimmer is deployed from a mini barge. Recovered oil is transferred to a Fastank (or fold-a-tank) on land. A vacuum truck transfers oil from the tank to Flow Station 2. Two workboats provide support.	R-33
	On Day 9, the wind shifts. The plume is deposited west of the well, cutting off access to MPI. Task Force 4 (on-pad liquid recovery), ceases operations.	R-6
	On Day 15, well control is achieved. Recovery crews have full access to the site. Task Force 4 (on-pad recovery by vacuum trucks), resume operations.	R-26
	Task Force 8: Oiled Gravel Recovery Once well control is achieved and liquid oil is recovered, crews begin recovery of contaminated gravel on a non-emergency basis. Dump trucks haul oiled gravel to temporary, lined stockpiles at the GPB Grind and Inject (G&I) facility. Onshore and pad oiled areas are cleaned up to ADEC's satisfaction by Day 30, the shortest possible time consistent with minimizing damage to the environment. The oil removal capacity illustrated in the scenario exceeds the response planning standard volume. See Table 1-13 and Table 1-14.	
(viii) Lightering Procedures	Mini barges and the freighter airboat offload liquids at MPI.	R-28

TABLE 1-12 (CONTINUED): : RESPONSE STRATEGY WELL BLOWOUT UNDER TYPICAL SUMMER CONDITIONS

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(ix) Transfer and Storage of Recovered Oil/Water; Volume Estimating Procedure	Liquids recovered north of the plumes are transferred to MPI processing facilities. The recovered fluids are pumped through a shut-in well via the top of the well head (crown nut). Recycling procedures are conducted with approval of ADEC. The fluids flow through the MPI separation system. Liquids recovered south of the plumes are transferred to Flow Station 2 for EOR. The liquids are manifested by waste specialists. Free water is decanted from mini barges or bladders with approval from the Unified Command and the EPA. Decanted liquids are pumped into recovery booms until oil is observed.	D-1
(x) Temporary Storage and Disposal	The Environmental Unit includes a Waste Management Team to: 1. Submit a plan to ADEC for waste management, 2. Measure liquid and other wastes, and 3. Fill out and sign manifests. Liquids are temporarily stored in vacuum trucks, mini barges, or Fastanks. The recovered liquids are then hauled to MPI or Flow Station 2 for recycling by vacuum trucks Non-liquid oily wastes are classified and disposed of accordingly. Non-oily wastes are classified and disposed of accordingly. Oiled gravel stockpiles are treated under an ADEC-approved long-term plan.	D-1 D-2, D-3, D-4
(xi) Wildlife Protection Plan	Resources at risk are primarily birds. The wildlife protection strategy is implemented. By Hour 6, a hazing team deploys by boat to the oiled delta and shorelines and another to oil slicks on Days 1 to 15. The Wildlife Stabilization Center is made operational and staffed by International Bird Rescue (IBR) staff by Hour 24. By Hour 6, a capture team deploys by boat to the nearshore spill area to monitor and capture oiled animals on Days 1 to 15. An aircraft monitors shoreline and nearshore areas in the oil trajectory daily on Days 1 to 15.	A-3 W-1, W-2B, W-5, W-3
(xii) Shoreline Cleanup Plan	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. Access to the river delta and shoreline with large equipment is limited. Primary delta and shoreline cleanup techniques include: • Burning of oily vegetation; • Deluge of minor to moderately oiled shoreline in the river, including those areas where heavier concentrations were manually removed; and • Natural recovery for those areas where residual staining may remain, but further recovery would cause more harm than good.	SH-1 B-2 SH-5 (2), SH-3 (1-2), SH-5 (2) SH-2

TABLE 1-13: OIL RECOVERY CAPACITY
WELL BLOWOUT UNDER TYPICAL SUMMER CONDITIONS

A	B	C	D	E	F	G
TASK FORCE / ACS SPILL RECOVERY TACTIC	**NUMBER OF SYSTEMS**	**RECOVERY AND HANDLING SYSTEMS**	**DERATED RECOVERY CAPACITY [BBL/HR]**	**MOBILIZATION AND TRANSIT TIME TO SITE [TIME]**	**OPERATING TIME [HR/DAY]**	**RECOVERY CAPACITY [BBLS/DAY] (B x D x F)**
PAD-BASED RECOVERY CAPACITY						
TF-4: On-Pad Recovery, R-6	2	Vacuum Truck	95.5[1]	8 hours	4	764
MARINE-BASED RECOVERY CAPACITY						
TF-5: Marine Recovery, R-17, R-32A	1	Crucial C Disc 13/30 Skimmer on shallow-draft workboat	31[2]	8 hours	20	620
CAUSEWAY-BASED RECOVERY CAPACITY						
TF-6: Hook-Boom Recovery, R-16	3	Crucial C Disc 13/30 Skimmer	31	8 hours	20	1,860
TF-6: Hook-Boom Recovery, R-16	1	Elastec drum skimmer, TDS-136	80	48 hours	20	1,600
TF-7: Swift Water Recovery, R-33	1	Crucial C Disc 13/30 Skimmer	31[2]	96 hours	20	620
Oiled Gravel Recovery Capacity						
TF-8: Recovery of Oiled Gravel, R-26	4	Dozer, Front-end loader, Skid steer, Two Dump trucks	28[3]	48 hours	20	2,240

[1] TF-4 liquid recovery rates are based on a distance of 2.5 road miles from the well to MPI processing. The time in transit, including load/unload time is 3.1 hours. The load time is calculated using an average pumping rate of 200 bbl/hr (summer rate). The assumed travel speed is 35 mph. In this scenario, TF-4 is assumed to recover 4 hours per day due to limited access to the pad.

[2] Based on the American Society for Testing and Materials (ASTM) Standard F2709-08 tests, the recovery rate for the Crucial 13/30 skimmer is 157 boph. According to 18 AAC 75.445 the de-rated capacity of the Crucial 13/30 skimmer is 31 boph (157 x 20% = 31).

[3] Dump Truck Recovery Calculation: $T_c/(L_t+T_t+U_t)$ =

20 yd^3/[0.17 hours + 20 miles from site to the GPB G&I facility * 2 trips/35 mph + 0.08 hour] = 14 yd^3/hr (with one dump truck)
Tc = Loader Capacity = 20 yd^3
Lt = Load Time = 0.17 hour
Ut = Unload Time = 0.08 hour

TABLE 1-14: MAJOR EQUIPMENT EQUIVALENTS TO MEET THE RESPONSE PLANNING STANDARD WELL BLOWOUT UNDER TYPICAL SUMMER CONDITIONS

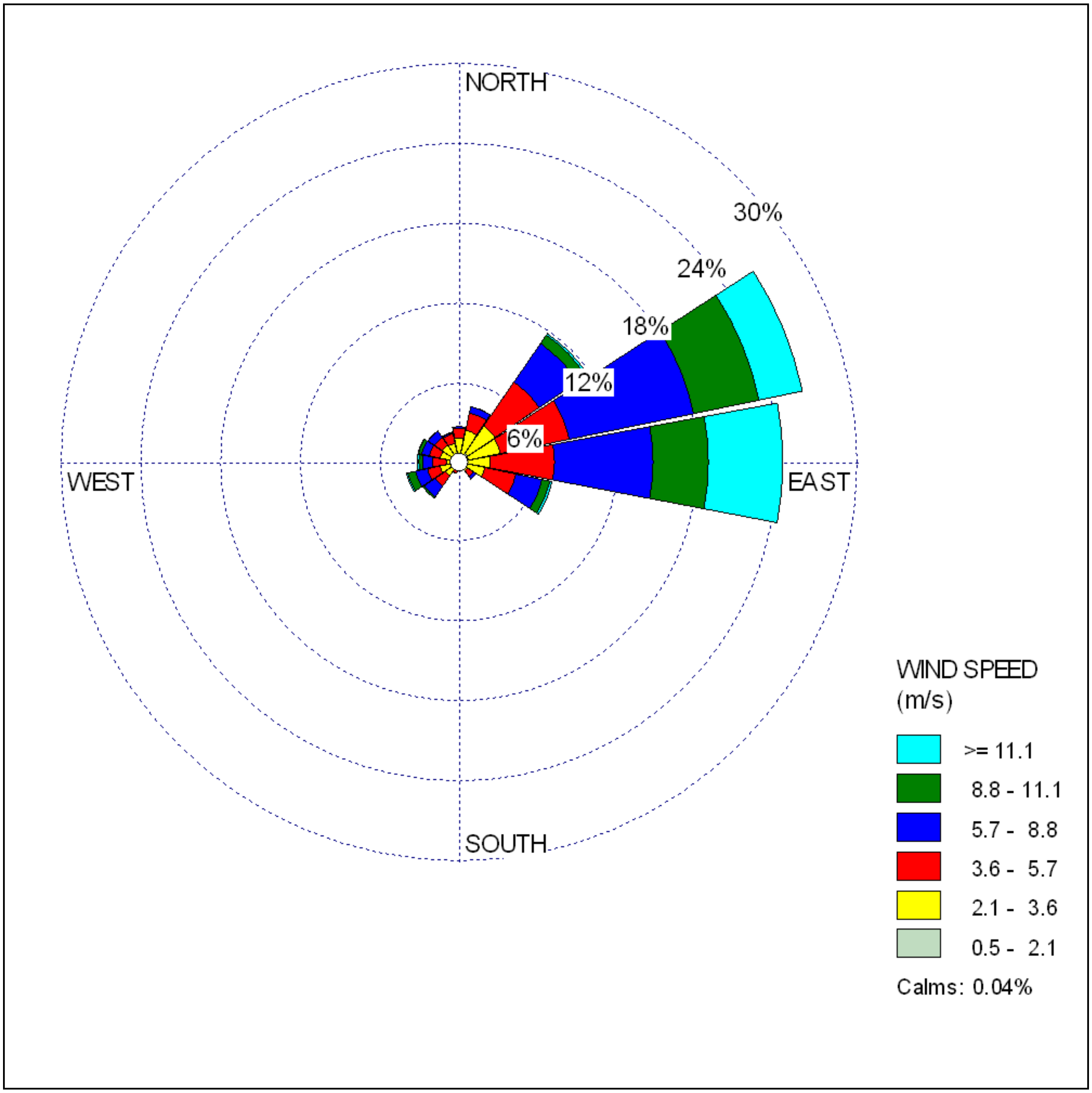
TASK FORCE	TACTIC	TOTAL QUANTITY
Task Force 1: Marine Shoreline Protection	C-13	Workboats 8 x 6 River Containment Boom Light Ocean Containment Boom Anchor system and onshore anchors
Task Force 2: Lagoon Area Containment	C-13, C-14	2 Airboats Containment Boom Anchor system and onshore anchors
Task Force 3: River Containment and Control	C-8	2 Workboats 8 x 6 River Containment Boom Anchor system and onshore anchors
Task Force 4: On-Pad Recovery	R-6	2 Vacuum Trucks
Task Force 5: Marine Recovery	R-17, R-32A	1 Crucial C Disc 13/30 skimmer 2 Workboats, Tow boom and mini barge, operate skimmer and pump
Task Force 6: Causeway Hook Boom Recovery	R-16	2 Airboats 8 Fastanks 3 Crucial C Disc 13/30 Skimmers 1 MiniMax 30 Skimmer 8 Pumps Suction Hose Discharge Hose 1 Vacuum Truck (shared with TF-4)
TF-7: Swift Water Recovery	R-33	2 Workboats 1 Crucial C Disc 13/30 skimmer Light Ocean Containment Boom or 1 Harbor Buster Boom System (with two air packs) 450 feet deflection boom Anchor system and onshore anchors 1 mini barge with double davits 1 transfer pump (Spate PD-75) 1 Discharge Hose 1 Suction Hose 1 Fastank or Fold-a-tank 1 Vacuum Truck
Task Force 8: Oiled Gravel Recovery	R-26	4 Dozers 4 Front-end loader 4 Skid steers 8 Dump trucks

TABLE 1-15: STAFF TO OPERATE OIL RECOVERY AND TRANSFER EQUIPMENT WELL BLOWOUT UNDER TYPICAL SUMMER CONDITIONS

LABOR CATEGORY	TASK FORCE	NO. STAFF ON DAY 1	NO. OF STAFF PER SHIFT TO SUSTAIN OPERATIONS
Large Vessel Operator (also the Team Lead)	TF-1: Marine Shoreline Protection	2	2
	TF-3: River Containment and Control	2	2
	TF-5: Marine Recovery	2	2
	TF-7: Swift Water Recovery	2	2
Small Vessel Operator (also the Team Lead)	TF-2: Lagoon Area Containment	2	2
	TF-6: Causeway Hook Boom Recovery	2	2
Team Lead	TF-1: Shore-based Containment,	1	1
	TF-4: On-Pad Liquid Recovery	2	2
	TF-5: Oiled Gravel Recovery	2	2
Skilled Technician	TF-1: Marine Shoreline Protection	5	5
	TF-2: Lagoon Area Containment	4	4
	TF-3: River Containment and Control	5	5
	TF-5: Marine Recovery	5	5
	TF-6: Causeway Hook Boom Recovery	8	8
	TF-7: Swift Water Recovery	5	4
General Technician	TF-6: Causeway Hook Boom Recovery	8	8
	TF-7: Swift Water Recovery	4	3
Equipment Operator	TF-3: Liquid Recovery	2 Vacuum trucks	2 Vacuum trucks
	TF-4: Marine Recovery	1 Vacuum truck	1 Vacuum truck
	TF-5: Oiled Gravel Recovery	-	4 Dozers 4 Front-end loaders 4 skid steer 8 Dump Trucks
	TF-7: Swift Water Recovery	1 Vacuum truck	1 Vacuum truck
	Total:	**65**	**83**

Note: Equipment operators are not necessarily members of the North Slope SRT.

FIGURE 1-5: AVERAGE WIND DIRECTION, MAY TO OCTOBER



Note:
Per convention, the wind rose illustrates direction of wind origin (i.e., where the wind is coming from). The wind data were retrieved from the Nearshore Beaufort Sea Meteorological Monitoring and Data Synthesis (Veltkamp and Wilcox, 2007) and a cooperative monitoring project between BPXA and Shell on Endicott's Endeavor Island.

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SCENARIO 3

WELL BLOWOUT DURING TYPICAL WINTER CONDITIONS

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TABLE 1-16: SCENARIO CONDITIONS
WELL BLOWOUT UNDER TYPICAL WINTER CONDITIONS

PARAMETER	PARAMETER CONDITIONS
Spill Location	Satellite Drilling Island (SDI) well 4-10A/L28.
Spill Time	January 15, 6:00 am, 15 days
Cause of Spill	Uncontrolled well blowout
Quantity of Spill	RPS volume = 857 bopd x 15 days = 12,855 bbl
Oil Type	Alaska North Slope Crude
Weather	Clear, -20 F
Wind Direction and Speed	During winter, the average wind speed is 11 knots. The predominant wind directions were determined from the 16 cardinal compass directions that blow over 10 percent of the time. For November through April, the predominant wind directions at Endicott are from the NE, E, and WSW. See Figure 1-9. The wind data were retrieved from the Nearshore Beaufort Sea Meteorological Monitoring and Data Synthesis (Veltkamp, B. and Wilcox, 2007) and a cooperative monitoring project between BPXA and Shell on Endicott's Endeavor Island. The weather data presented were collected during the winters of 2000 through 2011.
Trajectory	The scenario location was selected per ADEC regulations [18 AAC 75.434(e)]. Well 4-10A/L28 was the highest producing well according to AOGCC's production reports from January 2010 through December 2010. Simulated oil flows from the 4-inch (inner diameter) open orifice well at the rate of 857 bopd with GOR of approximately 7,440 standard cubic feet per barrel. The discharged oil takes the form of an aerial plume extending from the well to the SW, WSW, and W with the direction of prominent winds (ACS *Technical Manual* Tactic T-6). The S.L. Ross model (1997) indicates that 10 percent of the discharged oil is in the form of drops so small (50 µm or less) that they do not fall to the ground but are held aloft by atmospheric turbulence. For response planning purposes, the oil predicted by the model to remain airborne is proportionally distributed within the projected blowout plume footprint. Although all production wells are enclosed within facilities, the following scenario assumes an unobstructed blowout. The projected plume dimensions are approximately 2.7 miles long and 2,000 feet wide (at the widest point). See Figure 1-10. Approximately 71 percent (9,121 bbl) of the oil falls to the production pad. Approximately 80 percent of the discharged oil falls within 2,032 feet of the well. If left unrecovered for 15 days, the average thickness of the discharged oil deposited off-pad is 0.28 inches. The thickest portions of that oil are immediately west of the pad. Over a 15 day period, the following volumes are discharged: Days 1 to 5.8: 4,962 bbl are deposited to the east-northeast Days 5.9 to 11.1: 4,580 bbl are deposited to the west-southwest Days 11.2 to 15: 3,313 bbl are deposited to the west

TABLE 1-17: RESPONSE STRATEGY WELL BLOWOUT UNDER TYPICAL WINTER CONDITIONS

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(i) Stopping Discharge at Source	The On-Site Company Representative takes the role of Initial Deputy Operations Section Chief, and notifies the Drilling Superintendent, Operations Team Lead, and the affected ADW Team Lead. The IMT is activated. The affected ADW Well Manager calls well control specialists to obtain guidance for source control. Production is shut down, closing in the wells at the surface and subsurface. Personnel are evacuated when control is not immediate and safety is at risk. The Operations Team Lead assumes Surface Control leadership and plans initial surface controls.	A-1, A-2, L-2 BPXA IMS Manual
(ii) Preventing or Controlling Fire Hazards	The Operations Section Chief sets up access zones and routes and firefighting operations to protect assets and workers. Throughout the first few hours of the spill, the Operations Section Chief, with the assistance of the SSO and Fire Chief, verify no ignition sources in the area. The SSO determines response workers' PPE needs and provides hot and warm zone access information. The first draft of site safety plan (ICS Form 201-5) focuses on the delineation, containment and source control teams. It quickly evolves to include spill recovery teams. Monitoring protocol is established by the SSO at work areas for personnel protection. The monitoring protocol establishes safety zones according to applicable OSHA and fire hazard standards. Containment and recovery operations are conducted in accordance with site entry procedures. Recovery operations and oil field operations are disallowed downwind of the blowout well in areas where personnel may become exposed to flash fire hazard or oil particulate matter at concentrations greater than permissible exposure limits. Firewater coverage is set up by source control specialists.	S-1 through S-6
(iv) Surveillance and Tracking of Oil; Forecasting Shoreline Contact Points	Once safety zones and a decontamination unit have been set up, the oiled area is delineated. By Hour 2, aircraft is dispatched to delineate and monitor oil on snow and ice so it can be found after snowfall and blowing snow cover the oil. Oil falling to the sea ice is expected to stay in place and not move to shorelines.	T-1, T-4
(v) Protection of Environmentally Sensitive Areas and Areas of Public Concern	The Environmental Unit issues an advisory with the concurrence of the State Historic Preservation Officer. The Operations Section Chief directs that crews avoid the cultural sites as noted by the ACS Technical Manual Map Atlas and Alaska Heritage Resource Survey data. Catalogued cultural resource sites are listed on the maps that cover their vicinity in the spill area. The Technical Manual lists are adapted from the "North Slope Subarea Plan." Seal breathing holes offshore of MPI are identified by the Environment Unit and activity is restricted in the vicinity. Initially, there are no priority protection sites within the plume. At the end of Day 5, the wind shifts. The Environmental Unit Leader identifies priority protection sites PS 5 and PS 6 relying on the ACS *Technical Manual* descriptions and the Alaska Regional Response Team's North Slope Subarea Plan list of areas of concern.	W-6, ACS Map Sheet 74
(vi) Spill Containment and Control Actions	During the first shift, a BPXA Field Command Post, a decontamination unit, and staging area are established along the causeway. The Unified Command's objective is to contain and remove oil from the MPI, sea ice, and Sagavanirktok River delta by February 15.	L-2

TABLE 1-17 (CONTINUED): RESPONSE STRATEGY
WELL BLOWOUT UNDER TYPICAL WINTER CONDITIONS

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(vi) Spill Containment and Control Actions (continued)	Containment crews work cross-wind or upwind of the aerial plume. All containment and control activities are conducted in accordance with ACS site entry protocols.	
	Task Force 1: Pad Containment and Control The sheet pile wall provides effective containment on the north and east sides of SDI. By Hour 6, crews attempt to enhance on-pad containment on the north and northwest side of SDI. As conditions allow, crews begin construction of snow berms and placement of shore seal boom to contain the oil. Where possible, culverts are blocked with plugs, sandbags, or plywood.	C-1, C-3, C-4
	Task Force 2: Off-Pad Containment and Control By Hour 6, crews with earth moving equipment construct berms of snow. At heavier oiled areas, trenches are dug in the sea ice surface to direct oil flow to collection points. Two crews each supporting a trencher and one crew supporting a trimmer make the cuts in two shifts. The objective is to divert surface oil to containment pools.	C-1, C-11, C-12, C-19
	By Day 2, snow fencing is erected on the downwind and upwind sides of the lightly oiled snow to keep the wind from spreading the oiled snow.	
(vii) Spill Recovery Procedures	Recovery crews work cross-wind or upwind of the aerial plume. All recovery activities are conducted in accordance with ACS site entry protocols.	
	Task Force 3: On-Pad Liquid Recovery. As conditions allow, a vacuum truck is available to pump from pools of accumulating oil on the accessible portions on the north end of the pad.	R-6
	Task Force 4: Off-Pad Liquid Recovery. Off-pad liquid recovery is initiated with portable pumps, power packs, and Fastanks. As the ice road/pad allows improved access, vacuum trucks are also used. Oil is recovered from pools and trenches. See Figure 1-11.	R-6, R-7, R-13
	By Day 4, an ice road and pad is extended from the causeway to provide improved access and an additional staging area. The ice road supports wheeled traffic.	L-1, L-2
	At the end of Day 5, the wind shifts. The aerial plume shifts from the ENE to the WSW. Recovery of heavily oiled snow and ice is initiated in the ENE portion.	
	Task Force 5: Oiled Snow Recovery Loaders and skid steers selectively recover oiled snow. The snow is transferred to lined dump trucks and hauled it to a lined, temporary contaminated snow storage cell located adjacent to the Duck Island Gravel Mine.	R-1, R-3
	Task Force 6: Manual Snow/Tundra Recovery Manual recovery of lightly oiled snow is also initiated. The snow is shoveled into trailers and transported by snow machines to the staging area. At the staging area, the snow is loaded onto lined dump trucks for transfer to temporary storage at a lined, temporary contaminated snow storage cell located adjacent to the Duck Island Gravel Mine.	R-2
	On Day 11, the wind shifts again. Recovery crews adjust to the new orientation.	
	On Day 15, well control is achieved. Recovery crews have full access to the site.	
	Task Force 7: Oiled Gravel Recovery After the blowout has stopped, earth moving equipment and surface cleaning equipment clean up the MPI pad and its structures. After the surface structures have been cleaned, the oil-contaminated gravel is removed by a trimmer and backhoe. Loaders place gravel in lined dump trucks that haul it to the GPB G&I facility on a non-emergency basis.	R-5, R-26

TABLE 1-17 (CONTINUED): RESPONSE STRATEGY WELL BLOWOUT UNDER TYPICAL WINTER CONDITIONS

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(viii) Lightering Procedures	Not applicable	
(ix) Transfer and Storage of Recovered Oil/Water; Volume Estimating Procedure	On Day 1, vacuum trucks haul oil from the spill site to Flow Station 2 for EOR. The recovered fluids are manifested. Lined dump trucks haul oily snow to the temporary containment area. Oily gravel is taken to the GPB G&I facility.	D-1 D-5 D-4
(x) Plans, Procedures, and Locations for Temporary Storage and Disposal	The Environmental Unit includes a Waste Management Team to: 1. Submit a plan to ADEC for waste management, 2. Measure liquid and other wastes, and 3. Fill out and sign manifests. Vacuum trucks haul recovered oil to Flow Station 2 for EOR. Lined dump trucks haul oily snow to the temporary containment area. Snow is melted and taken to Flow Station 2 on a non-emergency basis. Oily gravel is hauled in lined dump trucks to the GPB G&I facility. Non-liquid oily wastes are classified and disposed of according to classification. Non-oily wastes are classified and disposed of accordingly.	D-1 D-5 D-4 D-2 D-3
(xi) Wildlife Protection Plan	Resources at risk are primarily seals. The wildlife protection strategy is implemented under agency permits. The Alaska Regional Response Team's (ARRT's) Hazing and Capture & Treatment Checklists are submitted to Unified Command. By Hour 2, a wildlife hazing team is deployed near MPI to target foxes and polar bears from Days 1 to 30. By Hour 2, polar bear guards and security staff trained to haze are assigned to protect bears and workers at remote winter operations from Days 1 to 30. Trained dogs locate seal structures from Days 2 to 30 ahead of on-ice response work, and response work near the structure is restricted.	A-3, W-6, W-1, W-2 W-5 W-3 W-2
(xii) Shoreline Cleanup Plan	A shoreline cleanup plan is submitted to Unified Command before break-up in case oiled shorelines are discovered after break-up. At break-up, Shoreline Cleanup Assessment Technique (SCAT) teams monitor the tundra and adjacent shorelines for oiling according to the plan and find none. On-shore and pad oiled areas are cleaned up to ADEC's satisfaction by Day 30, the shortest possible time consistent with minimizing damage to the environment. The oil removal capacity illustrated in the scenario exceeds the response planning standard volume.	SH-1

TABLE 1-18: OIL RECOVERY AND HANDLING CAPABILITY WELL BLOWOUT UNDER TYPICAL WINTER CONDITIONS

A	B	C	D	E	F	G
SPILL RECOVERY TACTIC	**NUMBER OF SYSTEMS**	**RECOVERY SYSTEM**	**RECOVERY RATE (yd^3/hr or boph)**	**MOBILIZATION AND TRANSIT TIME TO SITE**	**OPERATING TIME (hr/day)**	**HANDLING CAPACITY (yd^3/day or bbl/day) (B x D x F)**
TF-3 & TF-4: Liquid Recovery R-6, R-7	5	Vacuum truck or pumps to Fastanks.	58[1]	8 hours	20	5,800
TF-4: Liquid Recovery: R-13	4	Rope Mops (various sizes)	11	24 hours	20	880
TF-5: Mechanical Recovery of Oiled Snow: R-1, R-3	4	Dozer, Front-end loader, Skid steer, Two Dump trucks	48[2]	Day 4	20	3,840
TF-6: Manual Recovery of Oiled Snow: R-2	4	Shovels, brooms, snow machine, Front-end loader/ Dump truck	3	Day 15	20	240
TF-7: Recovery of Embedded Oil: R-5	3	Trimmer, Front-end loader, Two dump trucks	16[3]	Day 15, Non-emergency response	20	960

[1] Vacuum truck recovery calculation: Time = (miles to disposal * 2 trips / 35mph + 2(T_c/S_r),
Time = (21 miles from site to Flow Station 2 * 2 trips/35 mph) + 2(300 bbl / 150 boph) = 5.2 hours, where
T_c = Vacuum Truck Capacity = 300 bbl
S_r = Suction Rate = 150 boph

Oil recovery rate (ORR) = vacuum truck capacity/time,
ORR = 300 bbl/5.2 hours = 58 boph

For off-pad liquid recovery, strike teams can recover liquid oil at a rate exceeding 94 boph using portable pumps; however, transportation to FS-2 is conducted by vacuum truck, so the effective recovery rate is also 94 boph per strike team.

[2] Dump Truck Recovery Calculation: $T_c/(L_t+T_t+U_t)$ =
20 yd^3/[0.17 hours + 10 miles from site to temporary storage * 2 trips/35 mph + 0.08 hour] = 24 yd^3/hr (with one dump truck)
Tc = Loader Capacity = 20 yd^3
Lt = Load Time = 0.17 hour
Ut = Unload Time = 0.08 hour

[3] Dump Truck Recovery Calculation: $T_c/(L_t+T_t+U_t)$ =
20 yd^3/[0.17 hours + 20 miles from site to the GPB G&I facility * 2 trips/35 mph + 0.08 hour] = 14 yd^3/hr (with one dump truck)
Tc = Loader Capacity = 20 yd^3
Lt = Load Time = 0.17 hour
Ut = Unload Time = 0.08 hour

TABLE 1-19: MAJOR EQUIPMENT EQUIVALENTS WELL BLOWOUT UNDER TYPICAL WINTER CONDITIONS

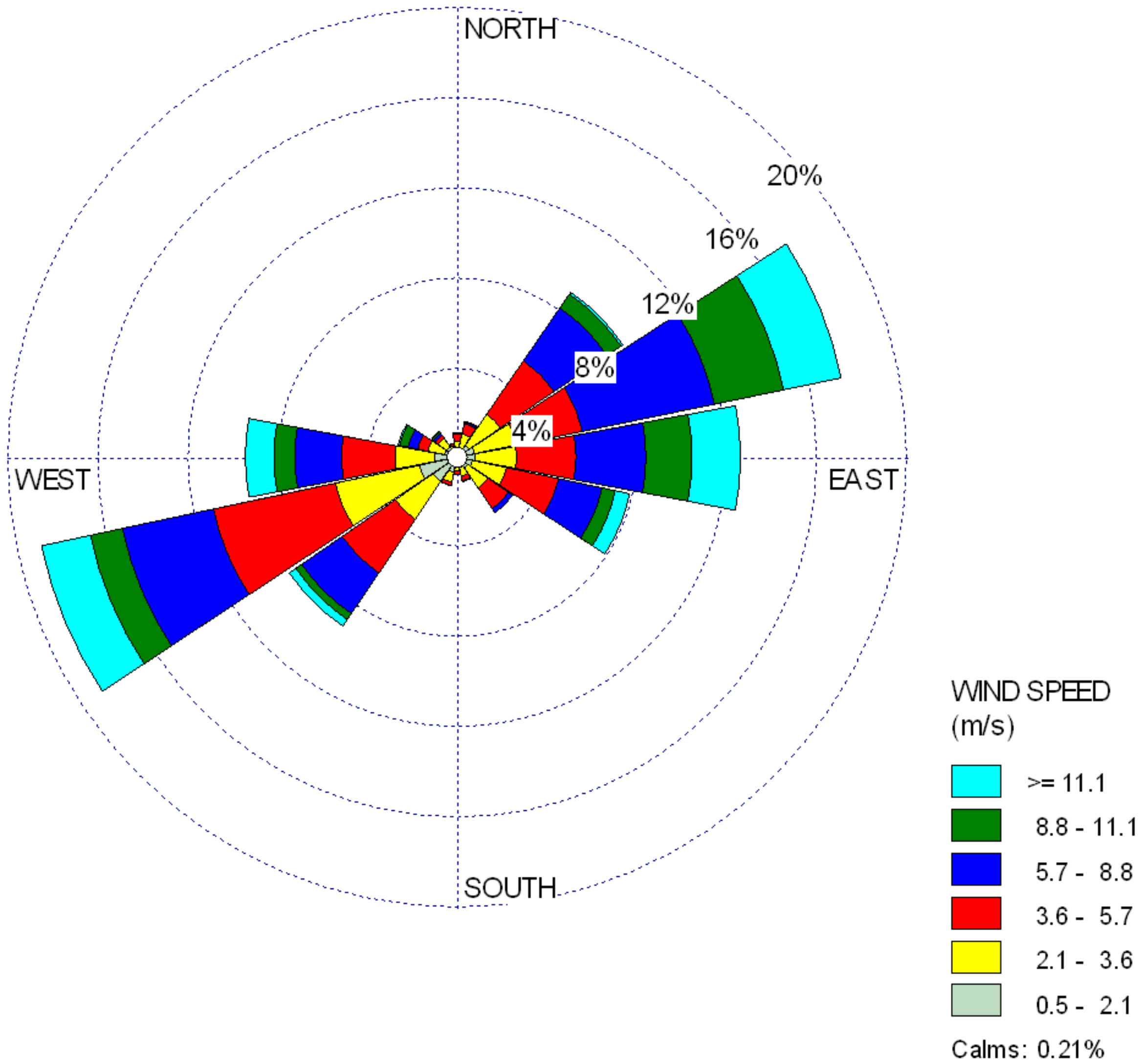
TASK FORCE / TACTIC	EQUIPMENT
Task Force 1: Pad Containment and Control (C-1)	2 Front-end loaders
Task Force 2: Off-Pad Containment and Control (C-1, C-11, C-12, C-19)	2 Trenchers 2 Trimmers Rube Witch with chainsaw 4 ATVs 500' Boom 17,000' Snow Fencing T–Posts and Wire Ties
Task Force 3: On-Pad Liquid Recovery (R-6)	2 Vacuum Trucks
Task Force 4: Off-Pad Liquid Recovery (R-6, R-7, R-13)	3 Vacuum Trucks 12 Fastanks 6 Trash pumps 4 Rope mops
Task Force 5: Oiled Snow Recovery (R-1, R-3)	4 Crawler Tractors 2 Front-end loaders 2 Skid steers 8 Dump Trucks
TF-6: Manual Recovery of Oiled Snow: (R-2)	Shovels, brooms 8 Snow machines 4 Front-end loaders 4 Dump trucks
TF-7: Recovery of Embedded Oil and Gravel (R-5, R-26)	3 Trimmers 3 Front-end loaders 3 Dump Trucks

TABLE 1-20: STAFF TO OPERATE OIL CONTAINMENT, RECOVERY, AND TRANSFER EQUIPMENT WELL BLOWOUT UNDER TYPICAL WINTER CONDITIONS

LABOR CATEGORY	TASK FORCE / TACTIC	NO. TACTICAL UNITS	NO. OF STAFF PER SHIFT DAY 1	NO. OF STAFF PER SHIFT DAY 4	NO. OF STAFF PER SHIFT TO SUSTAIN OPERATIONS
Team Leads	TF-1: C-1, C-3, C-4	1	1	1	1
	TF-2: C-1, C-11, C-12, C-19	1	1	1	1
	TF-3: R-6	2	1	1	1
	TF-4: R-6, R-7, R-13	3	1	1	1
	TF-5: R-1, R-3	4	-	1	1
	TF-6: R-2	4	-	4	4
	TF-7: R-5, R-26	3	-	-	1
Equipment Operators	TF-1:	1	3	-	3
	TF-2:	1	2 Trenchers 2 Trimmers	2 Trenchers 2 Trimmers	2 Trenchers 2 Trimmers
	TF-3	2	2, Vacuum Truck	2, Vacuum Truck	2, Vacuum Truck
	TF-4	3	3, Vacuum Truck	3, Vacuum Truck	3, Vacuum Truck
	TF-5	4	-	4 Crawler Tractor/ Tractor 2 Front-end loaders 2 Skid steers 8 Dump Trucks	4 Crawler Tractor/ Tractor 2 Front-end loaders 2 Skid steers 8 Dump Trucks
	TF-6	4	-	8, Snow Machines/ Tracked ATVs 4, Loaders 4, Dump Truck	8, Snow Machines/ Tracked ATVs 4, Loaders 4, Dump Truck
	TF-7	3	-	-	3, Trimmer 3, Front-end Loader 6, Dump Truck
Skilled Technician	TF-4	4	8	8	8
	TF-5	4	-	8	8
	TF-6	4	-	4	4
General Technician	TF-1	1	3	3	3
	TF-2	1	3	3	3
	TF-3	2	2	2	2
	TF-4	3	8	8	8
	TF-5	4	-	2	2
	TF-6	4	-	24	24
	TF-7	3	-	-	3
Total	**-**	**-**	**40**	**112**	**131**

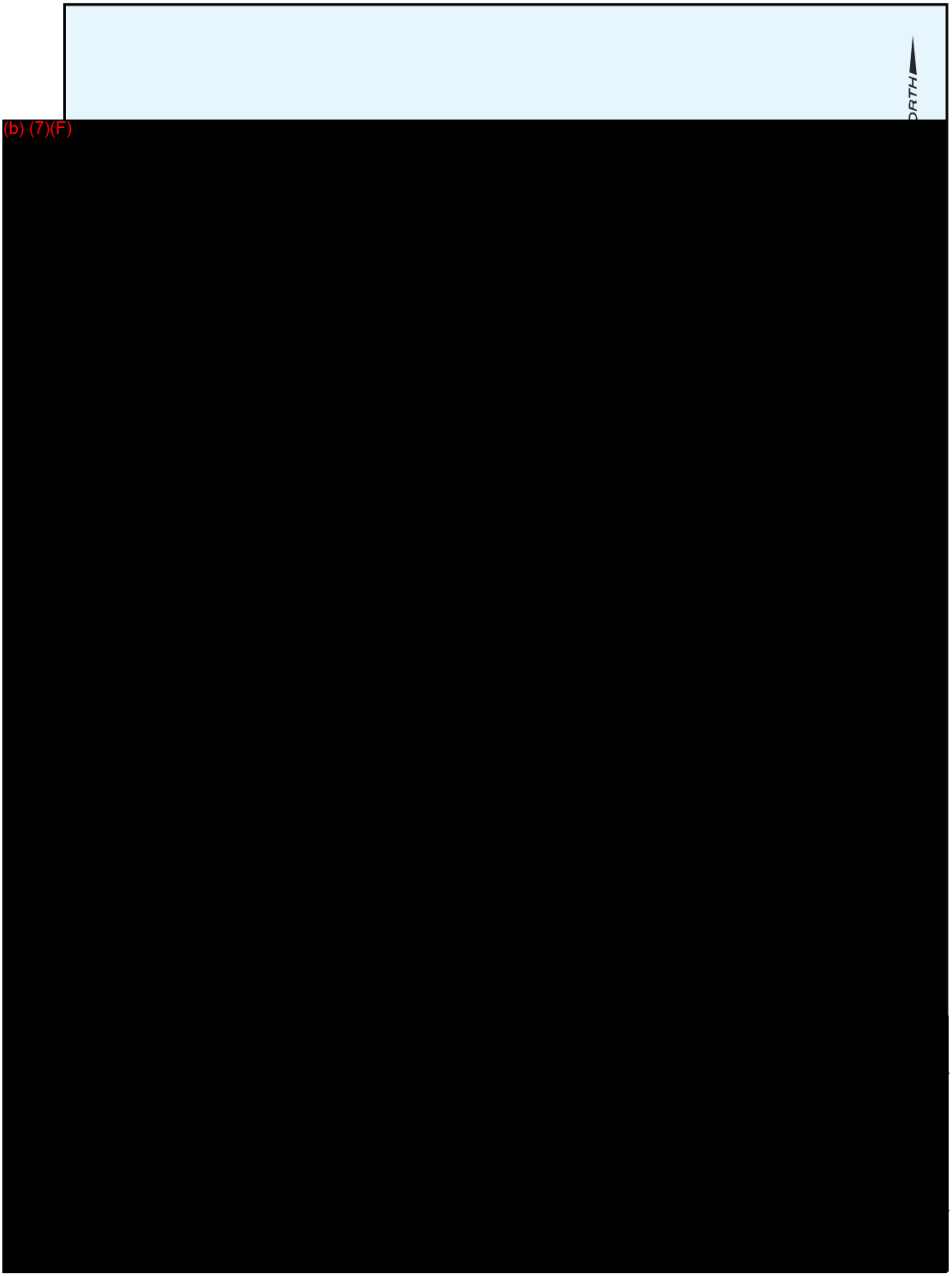
Note: Equipment operators are not necessarily members of the North Slope SRT.

FIGURE 1-9: AVERAGE WIND DIRECTION, NOVEMBER TO APRIL

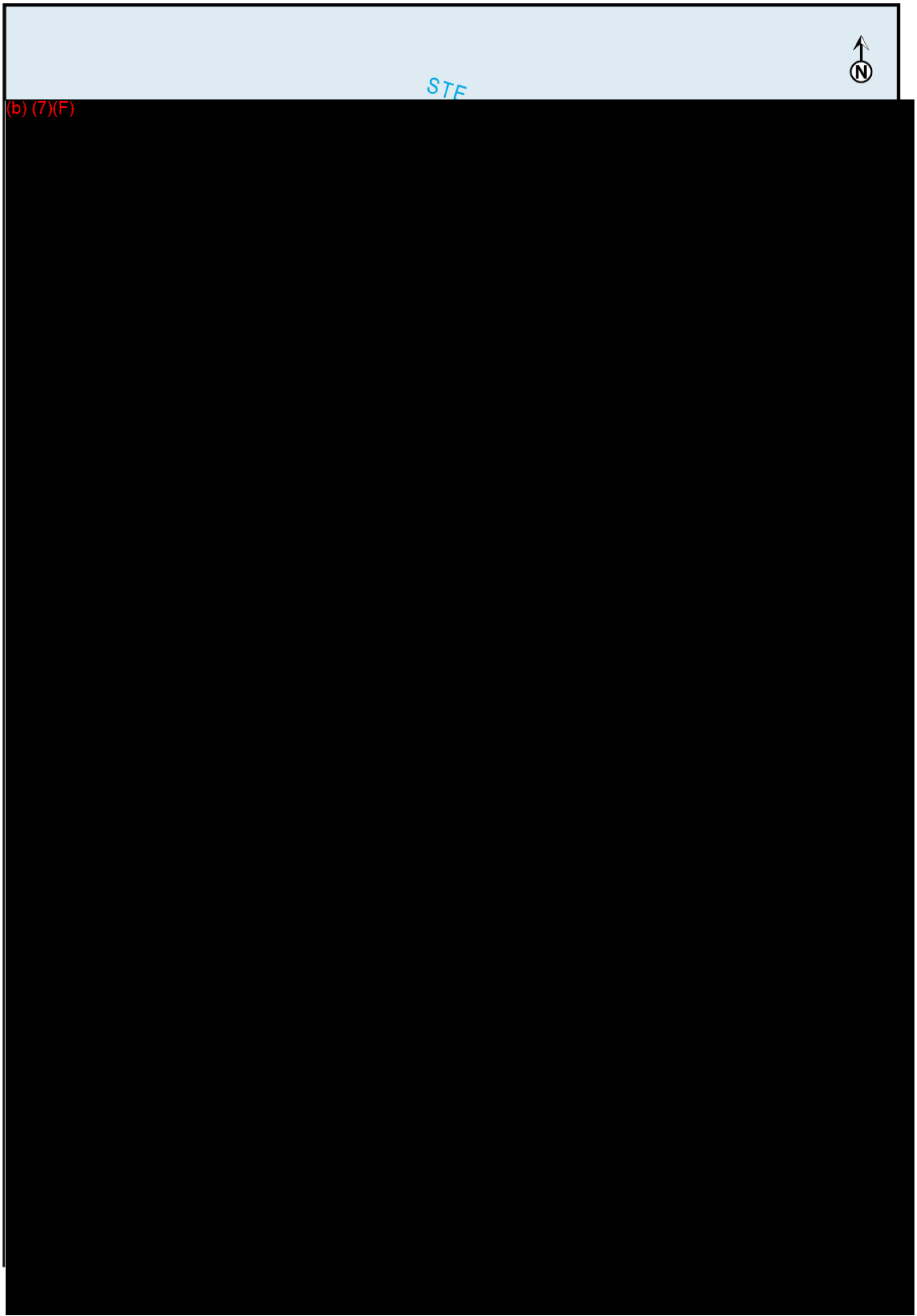


Per convention, the wind rose illustrates direction of wind origin (i.e., where the wind is coming from). The wind data were retrieved from the Nearshore Beaufort Sea Meteorological Monitoring and Data Synthesis (Veltkamp and Wilcox, 2007) and a cooperative monitoring project between BPXA and Shell on Endicott's Endeavor Island.

(b) (7)(F)



[redacted]



(b) (7)(F)

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SCENARIO 4

CRUDE OIL TRANSMISSION PIPELINE RELEASE

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TABLE 1-21: SCENARIO CONDITIONS
CRUDE OIL TRANSMISSION PIPELINE RELEASE

PARAMETER	PARAMETER CONDITIONS
Spill Location	The simulated rupture occurs where the Endicott Crude Oil Transmission Pipeline (COTP) crosses underneath the Endicott causeway, approximately 16,340 feet from the pig launcher at MPI. See Figure 1-12.
Date and Time of Spill	August 1, 5:00 pm
Source of Spill	Endicott COTP
Cause of Spill	Catastrophic rupture
Duration	Instantaneous
Quantity of Spill	Adjusted RPS volume = 3,724 bbl. Refer to Part 5 for RPS volume calculations.
Type of Oil Spilled	Endicott crude oil
Weather	Partly cloudy, 40°F
Visibility	Unrestricted
Wind Direction and Speed	From east-northeast at 10-20 knots
Surface Current	0.6 knots in Beaufort Sea
Trajectory	The discharged oil propagates centrically from the rupture point.

TABLE 1-22: RESPONSE STRATEGY CRUDE OIL TRANSMISSION PIPELINE RELEASE

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(i) Stopping Discharge at Source	The volumetric leak detection system alarms, and the pipeline flow is shut down at the Endicott MPI pumps. Within 15 minutes of leak alarm, the control room operator assesses the situation and dispatches Security to perform a drive-by visual inspection of the pipeline. The source is controlled by shut-in of operations.	A-1, A-2 BPXA IMS Manual
(ii) Preventing or Controlling Fire Hazards	The Fire Chief is on the scene with equipment and staff to suppress the threat of an explosion. Throughout the first few hours of the spill, the Fire Chief verifies that sources of ignition are shut down or removed from the area. The Endicott causeway is closed for nonessential traffic. Vehicular access to MPI is carefully controlled. The SSO provides access zone information and determines PPE requirements. The first draft of site safety plan (ICS Form 201-5) focuses on the delineation, containment and source control teams. It quickly evolves to include spill recovery teams. Monitoring protocol is established by the SSO for work areas to ensure personnel protection	S-1 through S-6
(iv) Surveillance and Tracking of Oil; Forecasting Shoreline Contact Points	By Hour 4 an aircraft is dispatched to monitor for oil. The slick is tracked by the aircraft, which records with a FLIR system. Approximately 4 hours after the aircraft has finished the survey, the infrared data is overlain on a digital map of the area, resulting in a detailed map of the spill. The system works during day or night conditions. By Hour 4, safety zones and a decontamination unit are set up. Then the oiled area is delineated. Survey crews assist in delineation of the plume and preparation of ground disturbance permits. By Day 2, excavation begins. The ruptured portion of pipeline is located. Test pits aid in delineation of the extent of the release. Field data are used to periodically update maps of the impacted area.	T-1, T-2, T-4
(v) Protection of Environmentally Sensitive Areas and Areas of Public Concern	The Environmental Unit issues an advisory with the concurrence of the State Historic Preservation Officer. The Operations Section Chief directs that crews avoid the cultural sites as noted by the ACS Technical Manual Map Atlas and Alaska Heritage Resource Survey data. Catalogued cultural resource sites are listed on the maps that cover their vicinity in the spill area. The Technical Manual lists are adapted from the "North Slope Subarea Plan." The Unified Command approves the activities and tactics used to protect environmentally sensitive areas and areas of public concern. Priority protection sites PS5, PS7, PS12 are located nearest the rupture. **Task Force 1: Exclusion Booming** By Hour 3, crews launch vessels from SDI and MPI. The crews deploy containment boom around all sides of the causeway intersection where the rupture is located. The objective is to keep oil from migrating outside of containment to the Sagavanirktok River delta or the Beaufort Sea. Light ocean and river containment boom is available at multiple locations along the Endicott causeway.	ACS Map Atlas Sheet 76 Tactic W-6 C-14

TABLE 1-22 (CONTINUED): RESPONSE STRATEGY CRUDE OIL TRANSMISSION PIPELINE RELEASE

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(vi) Spill Containment and Control Actions **and** **(vii) Spill Recovery Procedures**	A BPXA Field Command Post, decontamination unit, and staging area are established at the MPI on the first shift. **Support Task Forces** Support task forces set up on Shift 1. Marine-based recovery operations are staged at MPI and SDI. Staging and decontamination areas for land recovery operations are set up at MPI and Duck Island Gravel Mine. If necessary, decontamination for marine vessels is set up at MPI. All containment and recovery activities are conducted in accordance with ACS site entry protocols. **Task Force 2: Shore-based Containment** By Hour 3, gravel berms and shore seal boom are placed in a horseshoe shape ahead of the oil source to ensure the oil remains trapped in the immediate areas and depressions. Culverts are blocked with sandbags and plywood. **Task Force 3: Liquid Recovery** By Hour 4, vacuum trucks begin to collect pooled oil on the tundra and the pad by direct suction. A vacuum truck can effectively reach out 200 feet to recover oil. By Day 2, ground disturbance permits are obtained and liquid recovery operations are enhanced by excavating trenches. A SuperSucker is mobilized to remove liquids with solids that vacuum trucks cannot handle. **Task Force 4: Marine Recovery** Three portable skimmers are placed within the containment boom encircling the release site. Recovered oil is stored in Fastanks and transferred to MPI by vacuum trucks. **Task Force 5: Oiled Gravel Recovery** After all of the available liquids have been removed, excavation of oiled gravel begins. Front-end loaders excavate oiled gravel and load into lined dump trucks. A bulldozer or grader loosens compacted gravel as necessary. When the excavation nears utilities, crews excavate with shovels.	L-2 C-3, C-4 R-6, R-7 R-8 R-26
(viii) Lightering Procedures	Not applicable	
(ix) Transfer and Storage of Recovered Oil/Water; Volume Estimating Procedure	Recovered liquids are transferred to MPI processing facilities via vacuum trucks. The recovered fluids are pumped through a shut-in well via the top of the well head (crown nut). Recycling procedures are conducted with approval of ADEC. The fluids flow through the MPI separation system. The liquids are manifested by waste specialists.	D-1
(x) Plans, Procedures, and Locations for Temporary Storage and Disposal	The Environmental Unit includes a Waste Management Team to: 1. Submit a plan to ADEC for waste management, 2. Measure liquid and other wastes, and 3. Fill out and sign manifests. Non-liquid oily wastes and non-oily wastes are characterized and disposed of accordingly. Temporary storage facilities in bermed, lined pits are established at the MPI and the Duck Island Gravel Mine for contaminated soils stockpile treatment under a plan approved by the Unified Command and ADEC.	D-2 D-3 D-4

TABLE 1-22 (CONTINUED): RESPONSE STRATEGY
CRUDE OIL TRANSMISSION PIPELINE RELEASE

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(xi) Wildlife Protection Plan	Resources at risk are primarily birds. The wildlife protection strategy is implemented. By Hour 2, a hazing team deploys by boat to oiled shorelines and another to oil slicks on Days 1 through 3. The Wildlife Stabilization Center is made operational and staffed by IBR staff by Hour 24. By Hour 6, a capture team deploys by boat to the nearshore spill area to monitor operations.	A-3 W-1, W-2B, W-5, W-3
(xii) Shoreline Cleanup Plan	Shoreline cleanup operations are based on a plan approved by Unified Command. A shoreline assessment is conducted to understand the nature and extent of oiling beginning Day 1. Based on shoreline assessment, priorities are established for cleanup. Cleanup techniques chosen are based on shoreline type and degree of oiling. Most of the causeway shoreline is a narrow sand/gravel beach, with man-made structures at the causeway breaches and surrounding the SDI and MPI. Access to the shoreline with large equipment is limited by the narrow beach. Primary shoreline cleanup techniques include: • Manual recovery of heavier pockets of oil stranded along the Endicott Causeway shorelines, • Deluge of minor to moderately oiled shoreline in the river, including those areas where heavier concentrations were manually removed, and • Natural recovery for those areas where residual staining may remain, but further recovery would cause more harm than good.	SH-1 SH-5 (2) SH-3 (1-2 SH-2

TABLE 1-23: OIL RECOVERY CAPACITY CRUDE OIL TRANSMISSION PIPELINE RELEASE

A	B	C	D	E	F	G
SPILL RECOVERY TACTIC	**NUMBER OF SYSTEMS**	**RECOVERY SYSTEM**	**RECOVERY RATE (yd^3/hr or boph)**	**MOBILIZATION AND TRANSIT TIME TO SITE**	**OPERATING TIME (hr/day)**	**HANDLING CAPACITY (yd^3/day or bbl/day) (B x D x F)**
TF-3: Liquid Recovery R-6, R-7	2	Vacuum trucks	96[1]	4 hours	20	3,840
TF-3: Liquid Recovery R-7	2	SuperSucker	14	24 hours	20	560
TF-4: Marine Recovery R-8	3	Elastec TDS-118 drum skimmer.	26	24 hours	20	1,560
TF-4: Marine Recovery R-8	3	Elastec TDS-136 drum skimmer.	80	24 hours	20	4,800
TF-5: Recovery of Oiled Gravel R-26	4	Dozer, Front-end loader, Skid steer, Two Dump trucks	28[2]	Day 4	20	2,240

[1] Vacuum truck recovery calculation: Time = (miles to disposal * 2 trips / 35mph + 2(T_c/S_r),
Time = (2 miles from site to MPI * 2 trips/35 mph) + 2(300 bbl / 150 boph) = 5.2 hours, where
T_c = Vacuum Truck Capacity = 300 bbl
S_r = Suction Rate = 150 boph

Oil recovery rate (ORR) = vacuum truck capacity/time,
ORR = 300 bbl/5.2 hours = 58 boph

[2] Dump Truck Recovery Calculation: $T_c/(L_t+T_t+U_t)$ =
20 yd^3/[0.17 hours + 20 miles from site to the GPB G&I facility * 2 trips/35 mph + 0.08 hour] = 14 yd^3/hr (with one dump truck)
Tc = Loader Capacity = 20 yd^3
Lt = Load Time = 0.17 hour
Ut = Unload Time = 0.08 hour

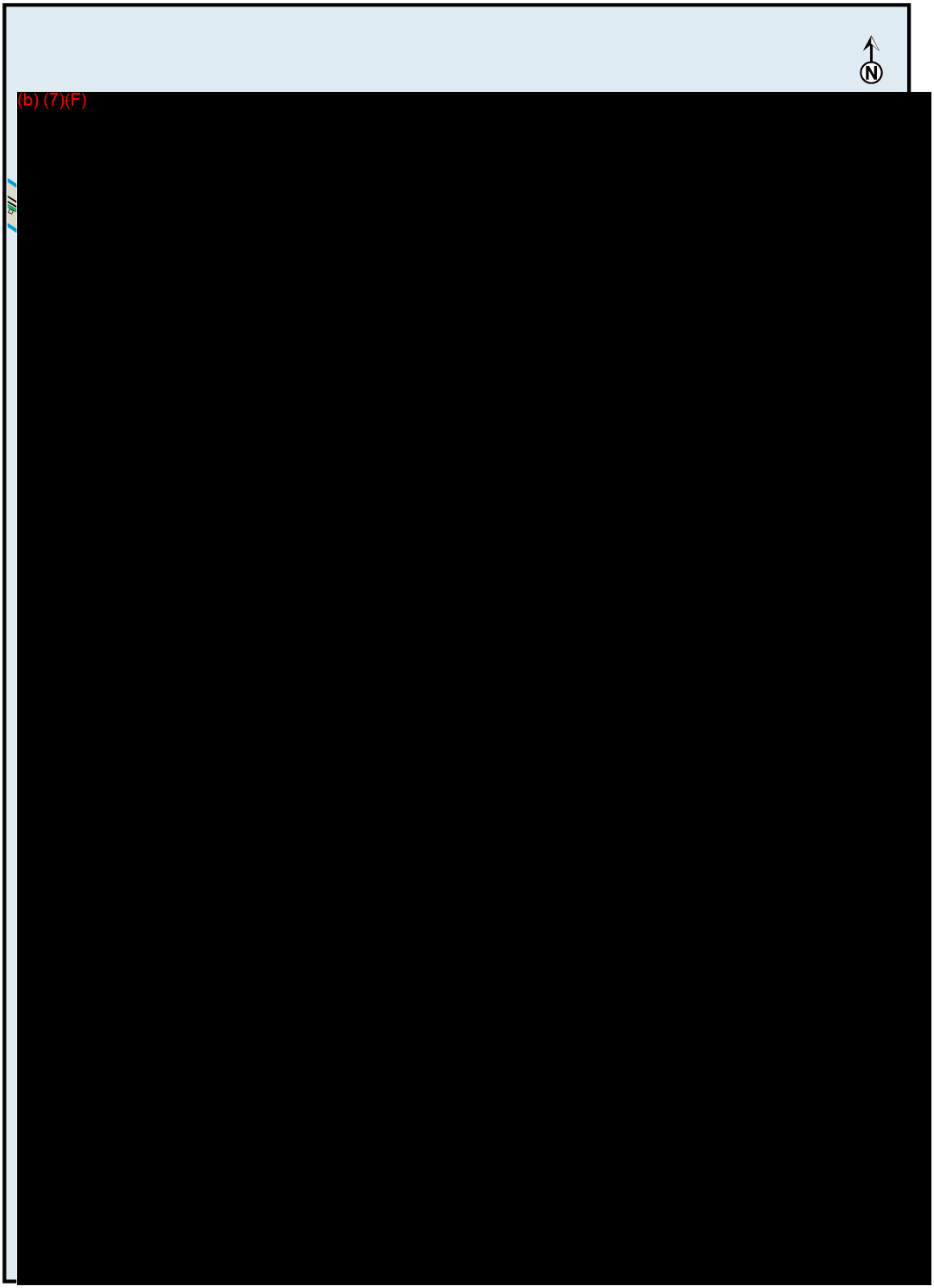
TABLE 1-24: MAJOR EQUIPMENT EQUIVALENTS TO MEET THE RESPONSE PLANNING STANDARD CRUDE OIL TRANSMISSION PIPELINE RELEASE

TASK FORCE / TACTIC	EQUIPMENT
TF-1 Exclusion Booming C-14	2 Workboats 8 x 6 River Containment Boom Light Ocean Containment Boom Anchor system and onshore anchors
TF-1 Shore-based Containment C-3, C-4	2 Front-end loaders Shoreseal boom culvert plugs or sand bags
TF-3 Liquid Recovery R-6, R-7	2 Vacuum trucks 2 SuperSuckers 1 Backhoe
TF-4 Marine Recovery R-8	2 Workboats 3 Elastec TDS-118 drum skimmers 3 Elastec TDS-136 drum skimmers 12 Fastanks 1 Vacuum truck
TF-5 Oiled Gravel Recovery R-26	1 Trimmer 1 Dozer 3 Front-end loaders 8 Dump Trucks

TABLE 1-25: STAFF TO OPERATE OIL RECOVERY AND TRANSFER EQUIPMENT CRUDE OIL TRANSMISSION PIPELINE RELEASE

LABOR CATEGORY	TACTIC	NO. STAFF ON DAY 1	NO. OF STAFF PER SHIFT TO SUSTAIN OPERATIONS
Large Vessel Operator (also the Team Lead)	TF-1 Exclusion Booming C-14	2	2
	TF-4 Marine Recovery R-8	2	2
Team Lead	TF-1 Shore-based Containment C-3, C-4	1	1
	TF-3 Liquid Recovery R-6, R-7	2	2
	TF-5 Oiled Gravel Recovery R-26	2	2
Skilled Technician	TF-1 Exclusion Booming C-14	5	5
	TF-4 Marine Recovery R-8	3	3
Equipment Operator	TF-1 Shore-based Containment C-3, C-4	2 Front-end loaders	2 Front-end loaders
	TF-3 Liquid Recovery R-6, R-7	2 Vacuum trucks 2 SuperSuckers 1 Backhoe	2 Vacuum trucks 2 SuperSuckers 1 Backhoe
	TF-4 Marine Recovery R-8	1 Vacuum truck	1 Vacuum truck
	TF-5 Oiled Gravel Recovery R-26	-	2 Dozers 3 Front-end loaders 8 Dump Trucks
	Total:	**25**	**38**

Note: Equipment operators are not necessarily members of the North Slope SRT.



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RESPONSE STRATEGY 1
ENDICOTT DIESEL TANK RUPTURE DURING SUMMER

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RESPONSE STRATEGY PARAMETERS

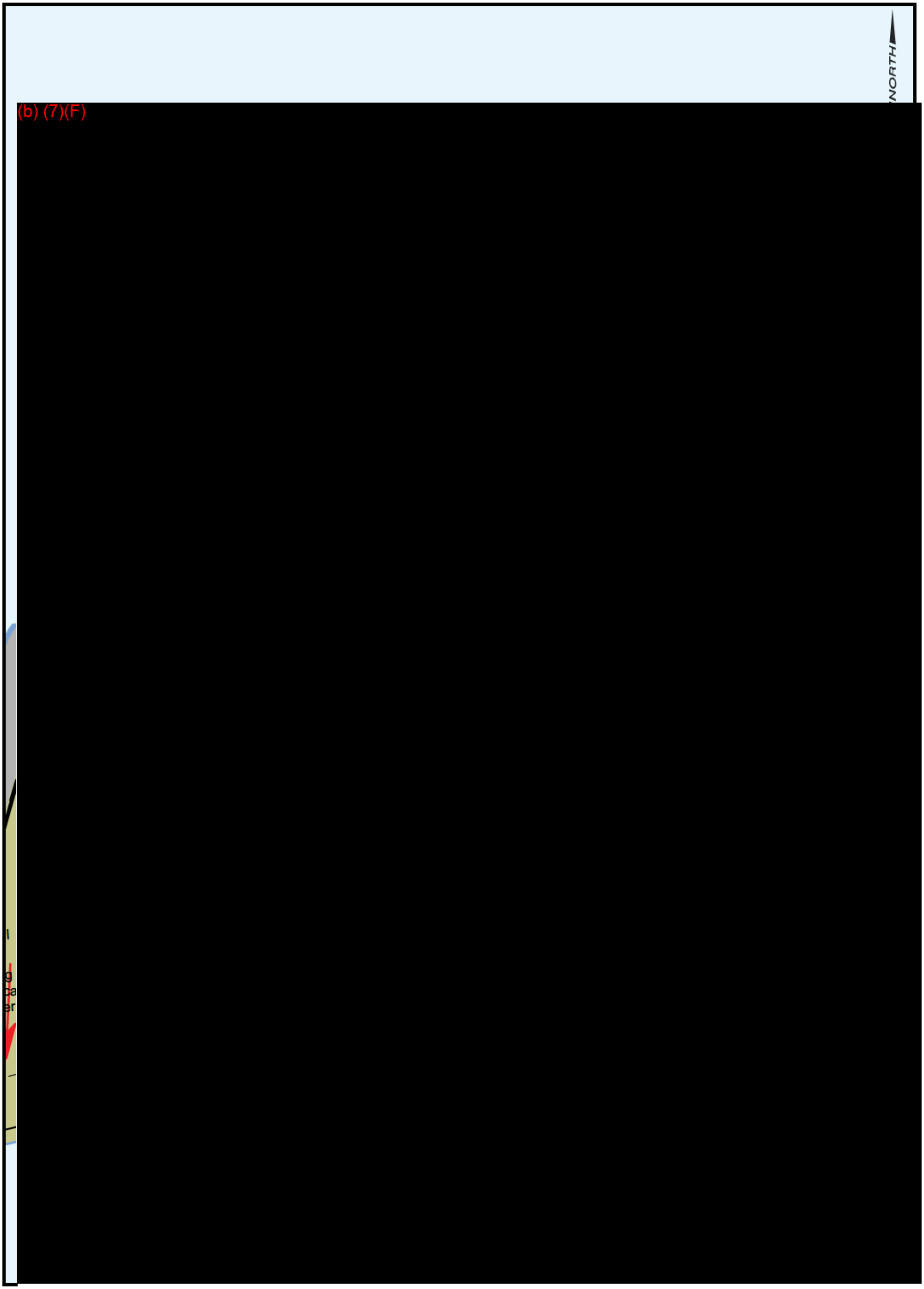
The following response strategy illustrates procedures and methods that may be taken in response to a hypothetical oil spill from Endicott's diesel storage tank, tank T-E3-3302. See Figure 1-13.

TABLE 1-26: ENDICOTT DIESEL TANK RUPTURE RESPONSE STRATEGY

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(i) Stopping Discharge at Source	The tank shut-in procedure is evaluated to ensure possible sources have been secured. Notification procedures begin, along with SRT mobilization. A staging area and field command post are established. Within the first few hours of the spill, Production Supervisors prepare a team to perform repairs to the tank. The team stabilizes the weakened area of the secondary containment with gravel to prevent further escape of diesel.	A-1, A-2, L-2 BPXA Incident Management System (IMS) Manual
(ii) Preventing or Controlling Fire Hazards	Throughout the first few hours of the spill, the Operations Section Chief with the assistance of the Site Safety Officer (SSO) verifies that sources of ignition are shut down or removed from the area. The Fire Chief is on the scene with equipment and personnel to suppress the threat of an explosion. The SSO and Operations Section Chief perform a visual inspection of the tank and a site safety assessment. After declaring the area clear, the SSO begins to prepare a site safety plan (ICS Form 201-5) including PPE requirements. The first draft of the site safety plan focuses on the delineation, containment, and source control teams. It quickly evolves to include spill recovery teams. Access to the spill site is carefully controlled and the scene is secured by Security. Monitoring protocol is established by the SSO for all work areas to ensure personnel protection.	S-1 through S-6
(iv) Surveillance and Tracking of Oil; Forecasting Shoreline Contact Points	Once safety zones and a decontamination unit have been set up by Hour 4, the oiled area is delineated. The extent of oil on the pad is delineated with lathe and/or hand-held global positioning systems (GPS) units. An aircraft is dispatched to monitor for oil in surrounding bodies of water and detects none.	T-1, T-2, T-4, T-7
(v) Protection of Environmentally Sensitive Areas and Areas of Public Concern	The Environmental Unit Leader identifies priority protection sites, relying on the ACS *Technical Manual* descriptions and the Alaska Regional Response Team's North Slope Subarea Plan list of areas of major Agency concern. The release is not expected to reach open water. Priority Protection Site 12 is the closest site, and includes seabird colonies. Exclusion and deflection booming tactics are the most effective methods of protection for seabirds. The area is monitored for birds and mammals that may be at risk from the spill. No cultural sites are identified in the vicinity.	ACS Map Atlas Sheet 67 W-6 C-13, C-14
(vi) Spill Containment and Control Actions	By the end of Hour 1, response teams are notified and activated. A staging area is established in the southern part of the production pad by Hour 2. Documentation of spill volume estimates are undertaken by Hour 4.	A-1, A-2, L-2

TABLE 1-26 (CONTINUED): RESPONSE STRATEGY
ENDICOTT DIESEL TANK RUPTURE RESPONSE STRATEGY

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(vi) Spill Containment and Control Actions (continued)	Task Force 1 – On-Pad Containment By Hour 2, the decontamination area is set up. By Hour 3, the SRT places shoreseal boom, sandbags, and gravel berms on the soiled perimeter of the pad to deflect and contain oil. Task Force 2 – On-Water Containment On Day 1, a strike team deploys prestaged equipment, which is located at MPI. The team deploys boom and anchors near the shoreline. Boom deployment takes the location of the seawater intake skid into consideration.	C-4 C-14
(vii) Spill Recovery Procedures	Task Force 3 – On-Pad Liquid Recovery By Hour 4, the vacuum truck begins to collect diesel from the pad and from the secondary containment. Task Force 4 – On-Pad Oiled Gravel Recovery On Day 2, after liquid recovery is complete, contaminated gravel is recovered with a front end loader and backhoe. The contaminated gravel is loaded into dump trucks with a back hoe, and hauled to a lined stockpile. Once characterized, the oiled gravel is taken to GPB G & I.	R-6 R-26
(viii) Lightering Procedures	Not applicable	Not applicable
(ix) Transfer and Storage of Recovered Oil/ Water; Volume Estimating Procedure	By Hour 2, the vacuum truck begins recovering fluids directly from the tundra and pad depressions. Fluids are hauled across the pad to the facility's liquid process tanks for processing. Liquids are gauged with Coliwasa tubes in tank trucks, manifested, and logged. Oily sorbents are hauled by ATV on plywood paths to the pad. Diesel volume in solids is estimated with grab samples.	D-1
(x) Plans, Procedures, and Locations for Temporary Storage and Disposal	Recovered diesel suitable for drilling freeze-protection is stored on site for later use. Unsuitable diesel that tests hazardous is drummed, stored and then shipped to an EPA-approved disposal facility. Non-hazardous diesel unsuitable for freeze-protection or in the production stream is injected into a disposal well. Non-liquid oily wastes are collected in plastic bags or other leak-proof storage containers and disposed of by incineration at Deadhorse. Contaminated gravel is excavated and stockpiled for waste characterization. The MPI storage pits have a capacity of 356 cubic yards. There are also two 18-cubic-yard storage bins. Diesel volume in solids is estimated with grab sample data.	D-1 D-2 D-4
(xi) Wildlife Protection Plan	Immediate response activities include the preparation of wildlife deterrent systems. On Day 1, a wildlife task force is deployed, and excludes birds and mammals from entering oiled areas. The wildlife stabilization and treatment center at Deadhorse is made operational and staffed by International Bird Rescue (IBR) staff by Hour 24. No oiled animals are encountered.	W-1 through W-6
(xii) Shoreline Cleanup Plan	Not applicable	Not applicable



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RESPONSE STRATEGY 2

WELL BLOWOUT DURING TYPICAL BROKEN ICE CONDITIONS

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QUALIFICATION STATEMENT

The following response description is not an ADEC-required response planning standard scenario. Rather, it is an ADEC-required response strategy to account for variations in receiving environments and seasonal conditions according to 18 AAC 75.425(e)(1)(F). The simulated blowout response begins at the onset of spring break-up. Well control is achieved 15 days later. The response continues throughout break-up.

The following response description is for illustration only. It is not a performance standard or a guarantee of performance. Some details are examples. Although some equipment is named, it may be replaced by functionally similar equipment. The response timelines are for illustration only. They 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 for an effective response without jeopardizing safety.

Actual responses are determined by the Unified Command, and depend on safety considerations, weather, and other environmental conditions, agency permits, response priorities, and other factors. In any incident, consideration for personnel safety is the highest priority. The response description assumes the agency on-scene coordinators and other agency officials immediately grant permits.

Larger responses than illustrated in this response description can be mounted with additional in-region resources and with the mobilization of out-of-region resources.

SIMULATED WEATHER AND SEA CONDITIONS AT SPILL SCENE

The scenario reflects historical ice and weather conditions that are described in Table 1-27. Air temperatures average 40°F in July and August, dropping to 30°F in September.

Ice floe maximum diameters are 500 to 1,000 feet in the first two days of break-up. They diminish to 30 to 40 feet within three weeks. The wind pushes ice of 7 tenths to 9 tenths coverage at 1 to 2 percent of wind speed, concentrations of 4 tenths to 6 tenths at 2 to 3 percent of wind speed, and 3 tenths and less at 3 to 4.5 percent of wind speed. Ice moves 30 degrees to the right of the wind direction.

Freeze-up begins October 1 in the area south of the Causeway, when the ice is considered shorefast for the season. Freeze-up begins on October 4 north of Endicott. Ice becomes shorefast for the season north of Endicott on October 25. Air temperatures range from 5 to 15°F. Daylight is 9 to 10 hours per day. Ice moves at 4 to 4.5 percent of the wind speed and 30 degrees to the right of the wind direction.

TABLE 1-27: SIMULATED ICE CONDITIONS DURING BREAK-UP

DAY	WIND	SUMMARY	ICE CONDITIONS
May 27	Variable	The Sagavanirktok River overflood reaches the area south of MPI. The north side of the island is not affected by overflood.	Condition 4 (stable ice) develops into Condition 5 (overflood) with the break-up of the ice in the Sagavanirktok River and the overflooding of the bottomfast and floating sea ice just offshore of the Sagavanirktok Delta. The Shaviovik and Kadleroshil k rivers also flood the landfast sheet ice, but their overflood zones are restricted to a distance of 1 to 2 miles offshore.
June 5	Variable	Overflood waters drain through the ice; breakup begins south of MPI. Stable ice north of MPI.	Condition 6 (decaying ice) and Condition 7 (initial break-up) in the Sagavanirktok River overflood zone. Overflood waters drain through the ice leaving a deteriorated but still intact ice surface. Bottomfast ice in the overflood zone has lifted off the bottom in most areas and is melting in situ.
June 15	From the NE	Blowout begins. Final break-up in the vicinity of the Big Skookum bridge. Initial break-up along the south side of the Endicott Causeway, farthest from the river discharge effects. Stable ice north of MPI.	Ice starts to fracture and open south of the Endicott Causeway. Ice conditions here are mostly a mix of open water holes, rotting small floes (in the order of 50 to 100 feet), and/or cakes of ice (tens of feet across by one foot thick) released from the bottom and melting rapidly in the warm, fresh river outflow. Bottom-fast ice persists along the south side of the Endicott Causeway, farthest from the river discharge effects. The landfast ice on the north side of Endicott is intact.
June 17	From the ENE		
June 30	From the E	Blowout ends.	
July 1	Variable	Open water on south side of Endicott Causeway. Decaying ice on north side of Endicott.	There is no ice south of the Endicott Causeway (Condition 9). A completely intact ice cover (floating and 3 to 4 feet thick), with many cracks and approximately 40 to 50 percent of its surface covered by meltpools, remains on the north side of Endicott.
July 4	Variable	Open water on south side of Endicott Causeway. Initial break-up on north side of Endicott.	Break-up begins with the remaining floating landfast ice on the north side of Endicott.
July 12	Variable	Open water on south side of Endicott Causeway. Final break-up on north side of Endicott.	Significant winds disturb the large ice floes north of Endicott. As the winds shift direction, the broken ice floes and pans move back and forth in belts and patches of varying concentrations, all the while melting. First year ice continues to deteriorate and break into smaller floes, creating considerable open water between floes.
July 19	Variable	Open water.	Ice Free – start of open water season. Ice invasion in the area after this date is possible, but unl kely.

Note:
1. Per convention, the wind states the direction of wind origin (i.e., where the wind is coming from). The predominant wind directions during the simulated blowout were determined from the 16 cardinal compass directions that blow over 10 percent of the time. The wind data were retrieved from the Nearshore Beaufort Sea Meteorological Monitoring and Data Synthesis (Veltkamp and Wilcox, 2007) a cooperative monitoring project between BPXA and Shell on Endicott's Endeavor Island.
2. Ice conditions are summarized from Dickins, D.F., K. Vaudrey, and SL Ross (2000).

TABLE 1-28: WELL BLOWOUT UNDER VARYING ICE CONDITIONS

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(i) Stopping Discharge at Source	The On-Site Company Representative takes the role of Initial Deputy Operations Section Chief, and notifies the Drilling Superintendent, Operations Team Lead, and the affected ADW Team Lead. The IMT is activated. The affected ADW Well Manager calls well control specialists to obtain guidance for source control. Production is shut down, closing in the wells at the surface and subsurface. Personnel are evacuated when control is not immediate and safety is at risk. The Operations Team Lead assumes Surface Control leadership and plans initial surface controls.	A-1 A-2, L-2 BPXA IMS Manual
(ii) Preventing or Controlling Fire Hazards	The Operations Section Chief sets up access zones and routes and firefighting operations to protect assets and workers. Throughout the first few hours of the spill, the Operations Section Chief, with the assistance of the SSO and Fire Chief, verify no ignition sources in the area. The SSO determines response workers' PPE needs and provides hot and warm zone access information. The first draft of site safety plan (ICS Form 201-5) focuses on the delineation, containment and source control teams. It quickly evolves to include spill recovery teams. Monitoring protocol is established by the SSO at work areas for personnel protection. The monitoring protocol establishes safety zones according to applicable OSHA and fire hazard standards. Containment and recovery operations are conducted in accordance with site entry procedures. Recovery operations and oil field operations are disallowed downwind of the blowout well in areas where personnel may become exposed to flash fire hazard or oil particulate matter at concentrations greater than permissible exposure limits. Firewater coverage is set up by source control specialists.	S-1 through S-6
(iv) Surveillance and Tracking of Oil; Forecasting Shoreline Contact Points	By Hour 4 an aircraft is dispatched to monitor for oil. The slick is tracked by the aircraft, which records with a FLIR system. Approximately 4 hours after the aircraft has finished the survey, the infrared data is overlain on a digital map of the area, resulting in a detailed map of the spill. The system works during day or night conditions. Aerial observation using the Shared Services Twin Otter provides real-time tracking of the leading edge of the oil on Day 1. NOAA is requested to provide trajectories. Projections are also made based on wind speed and direction.	T-2 T-4 T-5, T-6
(v) Protection of Environmentally Sensitive Areas and Areas of Public Concern	The Environmental Unit issues an advisory with the concurrence of the State Historic Preservation Officer. The Operations Chief directs that crews avoid the cultural sites as noted by the ACS *Technical Manual* Map Atlas and Alaska Heritage Resource Survey data. Catalogued cultural resource sites are listed on the maps that cover their vicinity in the spill area. The ACS *Technical Manual* lists are adapted from the "North Slope Subarea Plan."	W-6, Map Sheet 67

TABLE 1-28 (CONTINUED): WELL BLOWOUT UNDER VARYING ICE CONDITIONS

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(v) Protection of Environmentally Sensitive Areas and Areas of Public Concern (continued)	Sensitive areas could be impacted by the spilled oil. The marine and coastal bird and mammal populations and shoreline cultural resources occupying the path of the spilled oil described in the trajectory section potentially could be affected by oiling. Many of the birds and mammals are important both ecologically and economically. The ACS *Technical Manual*, Volume 2, lists the marine mammal groups and the marine bird groups that potentially may be exposed to the scenario's oil, and describes their seasonal distribution in the spill vicinity. The Unified Command approves the activities and tactics used to protect environmentally sensitive areas and areas of public concern. Priority protection sites PS5 and PS7 are within the blowout's aerial plume. The first strategy to protect resources of importance is to remove oil quickly and where it still lies in thick layers close to the spill source. Targeting that area can effectively reduce the quantity of oil available to move into sensitive areas later. A further strategy is to deploy exclusion and deflection boom at selected shoreline sites.	W-6, Map Sheet 67
	Offshore Shoreline Protection Task Forces As soon as conditions allow, str ke teams of workboats tow delta and harbor boom from West Dock and anchor it in shallow water. Exclusion booming and deflection booming tactics, including equipment lists, personnel numbers, procedures, and mobilization and deployment times, are described in ACS *Technical Manual* Tactics C-13, C-14, and C-15. The features of the vessels and boom are outlined in Tactic L-6. In the early hours of the spill response, hazing is carried out with ACS equipment and trained personnel under the direction and permits of the Alaska Department of Fish and Game and the U.S. Fish and Wildlife Service. Oiled carcasses are collected to remove them as sources of injury to predators. Oiled animals are captured, stabilized, and treated by specialists using ACS equipment, including the wildlife stabilization facility at Prudhoe Bay. Animals requiring further treatment are transported to the Alaska Wildlife Rehabilitation Center in Anchorage. See ACS *Technical Manual* Tactics W-1 to W-6 for decision-making and field procedures. On the fast sea ice, seal breathing holes are identified and avoided by response operators under advisories from specialists in the Wildlife Unit.	C-13 to C-15
(vi) Spill Containment and Control Actions **and** **(vii) Spill Recovery Procedures**	On Day 1, the Unified Command determines that the ice conditions south of MPI do not allow the option of hauling oil to shore with wheeled dump trucks and tankers. Consequently, Unified Command develops a plan to contain the discharged oil and burn in-situ. Equipment operations and workers on foot follow safety guidelines for vehicle load, ice thickness and ice condition, and for walking on deteriorating ice (Sandwell Engineering Inc., 2001). ACS and SRT oil containment and removal crews work in safety zones determined by the Site Safety Officer, following site entry protocols detailed in Tactic S-1 (ACS, 2010). By the end of Day 1, tracked personnel carriers, tracked Tucker trucks with blades, and other heavy equipment are mobilized from various locations in Prudhoe Bay to the staging area at Duck Island Gravel Mine, along the Endicott causeway, and on SDI. Decontamination facilities are set up at the Duck Island Gravel Mine staging area and SDI.	L-2 to L-6, L-8 to L-10, S-1

TABLE 1-28 (CONTINUED): WELL BLOWOUT UNDER VARYING ICE CONDITIONS

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(vi) Spill Containment and Control Actions **and** **(vii) Spill Recovery Procedures** **(continued)**	At the beginning of Day 2, a safe access work plan is implemented. Oil spill response technicians and equipment operators mobilize to begin recovery operations in the lagoon area (east of the causeway) where there is solid ice, and in broken ice conditions (west of the causeway).	S-1 to S-6
	Techniques that are used on land can also be used on solid ice. Partial trenches or through-ice slots are excavated in the ice surface with a trencher to encourage oil flow to a collection point. The machine cuts slots at the rate of 100 lineal feet per hour. Snow berms and boom are also used to divert oil to the trenches (Tactics C-11 and C-12). Oil that spreads to the east of the pad is contained and burned on solid ice and meltpools accessible by surface crews. Residue is collected with hand tools (Tactic B-6).	C-11, C-12, B-6
	To the west-southwest of MPI, oil is deposited to an area with decaying ice and broken ice. Unified Command authorizes the use of in-situ burning for this area. Access to this area is achieved by helitorch (Tactic B-3) and airboats (Tactic B-4). As conditions allow, conventional boom and fire boom is deployed in a stationary mode (either anchored to a shore or on the ice) to direct the oil to locations where it can be burned in-situ. If conditions do not allow for the deployment of boom, in-situ burning may be conducted by helitorch only (Tactic B-3).	B-3, B-4
	Due to variable and changing ice conditions, the teams move fire boom locations and modify tactics as necessary.	
	Transition to Open Water Season	
	As breakup continues the burning team's objective shifts from burning tactics to mechanical recovery methods (Tactic R-17). Conditions allowing mechanical recovery include when melting ice coverage falls to less than 10 percent. As conditions allow, shallow draft workboats tow delta containment boom in a J configuration and support a Crucial skimmer in the boom apex. Shuttle boats transport recovered oil and water to vacuum trucks stationed at a fluid transfer area set up on the causeway.	R-17
	Oil is stored in mini barges. The mini barges hold 100 barrels, less than their 249-barrel capacity, to reduce draft and prevent grounding. Two mini barges handle the loading, interim storage, and shuttling of recovered liquids. The recovery team loads a mini barge; the loaded mini barge is then shuttled with a workboat, offloaded, and returned to the recovery team. The mini barges, towed by workboats, offload at the fluid transfer area to vacuum trucks.	
	Burn residue can normally be picked up with large strainers or hand tools, with viscous-oil sorbents, or with standard viscous-oil skimmers (Tactic B-6), whether recovered from secondary booms or the fire containment boom.	B-6
	Burn residue and other non-liquid oily wastes are hauled in covered tote containers to the staging area by airboats for interim storage. Volumes are measured in the containers and logged on manifests. Residue is transferred by a freighter airboat with shuttling capacity exceeding the rate that becomes available. The freighter airboat travels an average of 10 mph on ice and water on 1-mile round trips.	
	During the blowout, a Liquid Transfer Task Force assembles at the staging area on the causeway. The stored liquids are offloaded from the mini barges to vacuum trucks (Tactic R-22). Once well control is achieved, the Liquid Transfer Task Force assembles at MPI. The volumes of stored oil and free water are gauged with ullage tape in the barge tanks.	R-22

TABLE 1-28 (CONTINUED): WELL BLOWOUT UNDER VARYING ICE CONDITIONS

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(vii) Spill Recovery Procedures (continued)	**Open Water Season** Beginning Day 15, well control is achieved. At that time, the water south of the causeway is ice free. Once the blowout is controlled and free liquids recovered, the Pad Recovery Task Force begins cleanup of the pad and its structures. Oiled gravel is removed with loaders and dump trucks.	R-26
(viii) Lightering Procedures	The mini barges, towed by workboats, offload at the fluid transfer area on West Dock to vacuum trucks.	R-28
(ix) Transfer and Storage of Recovered Oil/Water	Mini barges with tanks and vacuum trucks transfer oily liquids. Stored liquids are gauged with Coliwasa tubes in tank trucks and with ullage tape in mini barges. Waste liquids are manifested and logged by the Waste Management Team.	D-1
(x) Plans, Procedures, and Locations for Temporary Storage and Disposal	The Environmental Unit includes a Waste Management Team to: 1. Submit a plan to ADEC for waste management, 2. Measure liquid and other wastes, and 3. Fill out and sign manifests. Burn residue and non-liquid oily wastes are transported and handled for ultimate disposal appropriately, as recommended in the Alaska Waste Disposal and Reuse Guide. Liquid and non-liquid oily wastes are processed as described in Tactics D-1 and D-2. Temporary storage facilities are established at the pad adjacent to the Duck Island Gravel Mine and MPI for oily wastes offloaded from the mini barges. Oily liquids are hauled to the FS2 processing facility by truck. Oiled gravel is stored in lined containment cells constructed at the pad adjacent to the Duck Island Gravel Mine. Waste Team members measure the fraction of oil in gravel and calculate volume of oiled materials stored in the lined pits. After characterization, the oiled gravel is transported to the GPB DS4 G&I facility on a non-emergency basis.	D-1 through D-4
(xi) Wildlife Protection Plan	Priority protection areas are boomed to exclude oil from critical habitats. The wildlife protection strategy is implemented. Wildlife hazing teams are deployed by boat along shorelines and standby to haze if the shorelines become oiled. Deployment of bird scare buoys is considered. The Wildlife Stabilization Center is made operational.	A-3, W-6 W-1 W-2B W-5
(xii) Shoreline Cleanup Equipment	Mainland onshore areas downwind of the blowout are monitored by assessment teams to determine the distribution of oil on tundra and shorelines. The teams search for oiled areas from a helicopter and from two Rolligons operating under an emergency tundra travel permit. The teams employ assessment protocols specific to Alaska and arctic environments (NOAA, 1994; NOAA, 2000; USCG, 2010).	SH-1, T-1, T-2

TABLE 1-28 (CONTINUED): WELL BLOWOUT UNDER VARYING ICE CONDITIONS

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(xii) Shoreline Cleanup Equipment (continued)	Shoreline cleanup teams recover oil on marine shorelines using methods recommended by the assessment teams, reflected in a shoreline cleanup plan, and approved by the Unified Command. The majority of the shoreline is a narrow sand/gravel beach, with minor amounts of tundra cliffs and peat. Access to the shoreline with large equipment is limited due to the narrow nature of the beach and limited access points. Primary shoreline cleanup techniques would include:	
	• Manual recovery of heavier pockets oil stranded along the beach,	SH-5
	• Deluge of minor to moderately oiled shoreline, including those areas where heavier concentrations were manually removed,	SH-3
	• Passive recovery (use of sorbents) and oiled vegetation cutting for any vegetated areas impacted,	SH-7
	• High-pressure wash and/or steam cleaning of the man-made structures along the West Dock Causeway, and	SH-4
	• Natural recovery for those areas where residual staining may remain, but further recovery would cause more harm than good.	SH-2

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RESPONSE STRATEGY 3

BADAMI CRUDE OIL TRANSMISSION PIPELINE RELEASE DURING SUMMER

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RESPONSE STRATEGY PARAMETERS

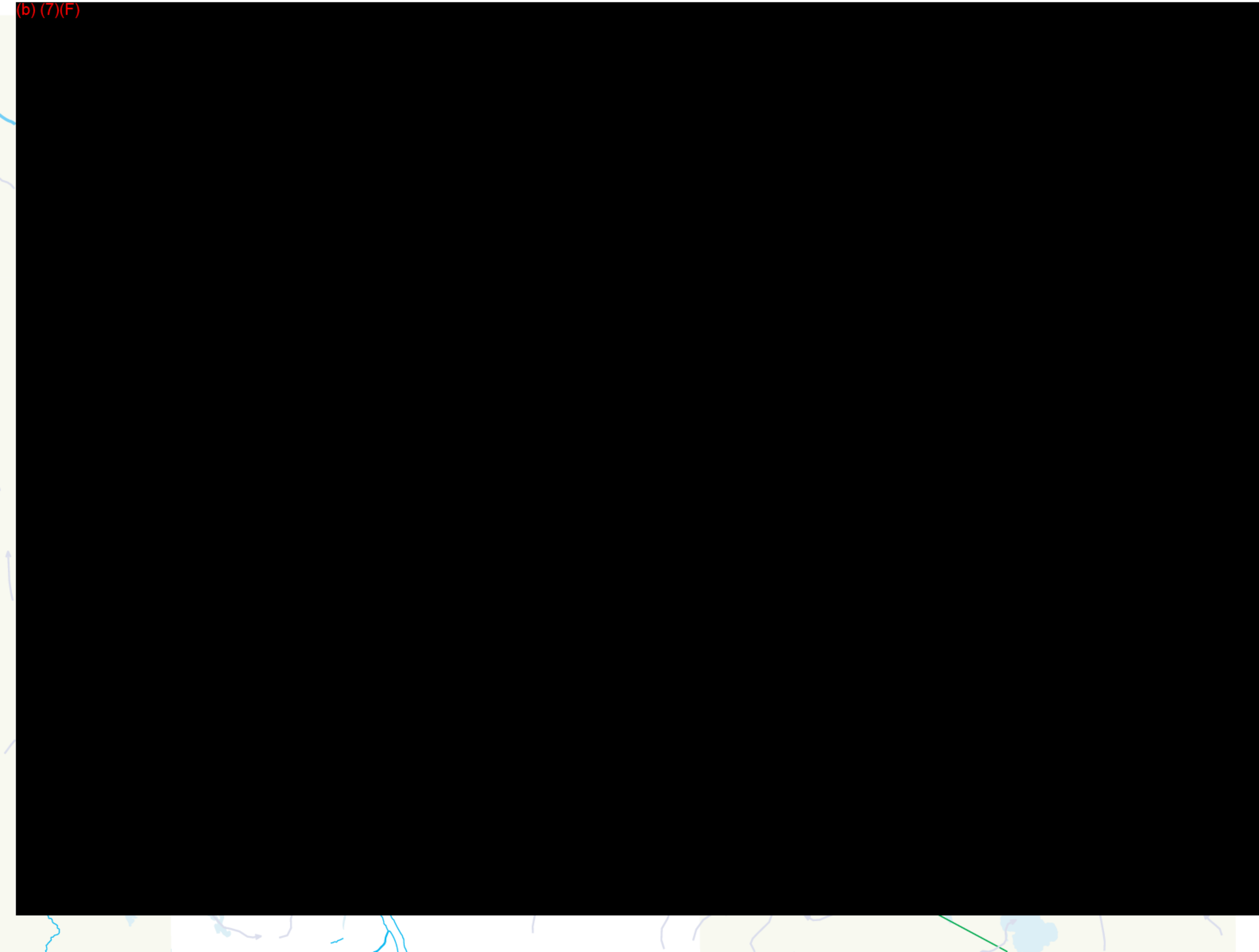
The following response strategy illustrates procedures and methods that may be taken in response to a hypothetical oil spill from Badami's crude oil transmission pipeline. See Figure 1-14.

TABLE 1-29: BADAMI CRUDE OIL TRANSMISSION PIPELINE RELEASE DURING SUMMER RESPONSE STRATEGY

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(i) Stopping Discharge at Source	The leak detection system alarms, and the pipeline is shut down. [redacted] ssing are manually closed by Hour 3.	A-1, A-2 BPXA IMS Manual
(ii) Preventing or Controlling Fire Hazards	Safety personnel are mobilized to the site. The SSO provides access zone information and determines PPE requirements. The first draft of site safety plan (ICS Form 201-5) focuses on the delineation, containment and source control teams. It quickly evolves to include spill recovery teams. Monitoring protocol is established by the SSO for work areas to ensure personnel protection.	Not applicable
(iv) Surveillance and Tracking of Oil; Forecasting Shoreline Contact Points	By Hour 4 an aircraft is dispatched to monitor for oil. The slick is tracked by the aircraft, which records with a FLIR system. Approximately 4 hours after the aircraft has finished the survey, the infrared data is overlain on a digital map of the area, resulting in a detailed map of the spill. The system works during day or night conditions. By Hour 8, safety zones and a decontamination unit are set up. Then the oiled area is delineated. Field data are used to periodically update maps of the impacted area. NOAA is requested to provide trajectories. Projections are also made based on wind speed and direction.	T-4 T-5
(v) Protection of Environmentally Sensitive Areas and Areas of Public Concern	Potential oil impact areas and priority protection sites are identified with oil slick trajectory modeling. Priority protection sites PS4 and PS3D are boomed to exclude oil from sensitive habitat areas and areas of public concern. Approximately 2,000 feet of boom are needed to protect the two sites. 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.	See Map Sheet 86 C-14
(vi) Spill Containment and Control Actions **And** **(vii) Spill Recovery Procedures**	**River Containment, Control and Recovery** A task force from Badami travels to the Kadleroshilik River and deploys pre-staged equipment located at BAD-2 by Hour 3. The prestaged equipment includes 1,125 feet of boom, a drum skimmer, and a 2,500-gallon open top tank. A task force from Endicott travels to the Kadleroshilik River and brings boom, bladders, Fastanks, skimmers, and pumps on airboats to deploy in the river delta by Hour 8. Skimmed oil is stored in bladders and Fastanks.	C-8, R-24 (3)

TABLE 1-29 (CONTINUED): BADAMI CRUDE OIL TRANSMISSION PIPELINE RELEASE DURING SUMMER RESPONSE STRATEGY

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(vi) Spill Containment and Control Actions **And** **(vii) Spill Recovery Procedures** **(continued)**	**Marine Containment, Control and Recovery** Marine recovery vessels with boom and skimmers are positioned offshore in 3-foot water depth and west of the Kadleroshilik River delta. The str ke teams position in front of the leading edge of the oil, following mobilization and transit from West Dock and deployment offshore of the Kadleroshilik River delta.	R-17
(viii) Lightering Procedures	Freighter airboats with tanks and mini barges offload at the dock at Endicott.	R-28
(ix) Transfer and Storage of Recovered Oil/Water; Volume Estimating Procedure	The Environmental Unit includes a Waste Management Team to: 1. Submit a plan to ADEC for waste management, 2. Measure liquid and other wastes, and 3. Fill out and sign manifests. At river containment sites, Fastanks and bladders store the liquid. The liquid is transferred to freighter airboats and taken to Endicott for processing. Mini barges shuttle stored liquids from marine oil recovery teams. Liquids are processed through the Endicott Processing Facility and are manifested. Coliwasa tubes in vehicle tanks and ullage tape in mini barges gauge water and oil cut for logging by waste specialists.	R-25 R-17 D-1
(x) Plans, Procedures, and Locations for Temporary Storage and Disposal	Temporary storage facilities are established at the MPI for contaminated soils and oily wastes according to a shoreline cleanup plan approved by Unified Command (See Section xii). Wastes are characterized and disposed of accordingly.	D-2, D-3, D-4
(xi) Wildlife Protection Plan	Immediate response activities include the preparation of wildlife deterrent systems. A wildlife task force excludes birds and mammals from entering oiled areas onshore and on water, monitors the oil trajectory area, recovers oiled carcasses and captures oiled wildlife. The task force operates from skiffs and on foot. A wildlife stabilization and treatment center is made operational and is staffed by IBR staff.	W-1 through W-6
(xii) Shoreline Cleanup Plan	Shoreline cleanup operations are based on a plan approved by Unified Command. A shoreline assessment is conducted to understand the nature and extent of oiling beginning Day 1. Based on shoreline assessment, priorities are established for cleanup. Cleanup techniques chosen are based on shoreline type and degree of oiling. Crews flush low-pressure water into collection pits or shore seal boom areas where the oil is collected with skimmers and sorbents.	SH-1, SH-2, SH-3, SH-5, SH-7 and SH-10 R-4, R-9



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

BPXA will request approval for in-situ burning from the State and Federal On-Scene Coordinator (SOSC and FOSC, respectively) when mechanical response methods prove ineffective or as a tool to minimize environmental damage.

Burning will not be initiated without approval of state and federal agencies. Authorization to burn will be received after completing the “Application and Burn Plan” form in Revision 1 of the “In Situ Burning Guidelines” within Annex F of the *Alaska Federal/State Preparedness Plan for Response to Oil and Hazardous Substance Discharges/Releases* (Unified Plan), Volume 1. The form is retrieved via the internet at www.akrrt.org and http://www.alaska.gov.

In-situ burning of spilled oil will be considered under conditions such as those that follow:

- 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, and
- A successful test burn has been conducted.

If the BPXA Incident Commander decides to use in-situ burning and obtains the necessary authorization, ACS will carry out the response. ACS maintains the equipment and personnel for in situ burning. The equipment and personnel are described in ACS *Technical Manual*, Tactics B-2 to B-7, incorporated here by reference.

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

Facility diagrams are located in Volume 2 of the Endicott Oil Discharge Prevention and Contingency Plan.

1.9 RESPONSE SCENARIO FOR AN EXPLORATION OR PRODUCTION FACILITY [18 AAC 75.425(e)(1)(I)]

1.9.1 RESPONSE STRATEGY FOR WELL BLOWOUT CONTROL

A summary of planned methods, equipment, logistics, and time frames to control a well blowout within 15 days, required by 18 AAC 75.425(e)(1)(I), is provided below.

The estimated timeframe to secure a well blowout by means of a well-capping program is 15 days, excluding weather days and other contingencies. Mobilization of specialist teams, initial equipment and initiation of well intervention planning would be expected to take three to four days. On-site preparations would take another three to four days. Concurrently, access and safety, well capping engineering and well re-entry would be planned and decontamination facilities and off-site operations facilities would be set up. Uncontrolled fluids may be diverted for collection and handling to create a safe working environment and minimize pollution. The blow out prevention equipment would be removed from the well if necessary. The capping stack would be installed within several days to provide containment, and the uncontrolled release of hydrocarbons is terminated by Day 15.

Well control specialists will be notified immediately in the event of a well control situation with the potential to escalate. BPXA ADW currently has an agreement with Boots and Coots Services, a single point of contact to provide services for well control response. Such 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 specialty fluids, chemicals and additives. The 24-hour phone numbers for Boots and Coots are found in Table 1-2.

BPXA maintains and has available fulltime on the North Slope most of the major equipment for well firefighting to initiate well-capping or other surface control options. Additional equipment, which may be required on a case by case basis, will be supplied through well control specialists or other vendors. Specialized equipment for well firefighting and well-capping is summarized in Table 1-41. BPXA may loan well control equipment to other North Slope operators in emergencies. The equipment mobilization and travel times in Table 1-41 do not apply to equipment loaned to other operators.

The equipment listed in Table 1-41 presents a broad spectrum of resources that could be used during a well blowout response. Not all pieces of equipment are required to be at the staging area concurrently. The well capping team conducts activities in a preferred sequence, so tools and deliverables are on site when they are needed in the well capping process. The mobilization and travel times presented in Table 1-41 are not based upon "zero hour" of an uncontrolled release, but are estimates of the periods between the original request by the user and the equipment's arrival at the emergency staging area. The estimates exclude weather contingencies.

The decision logic regarding well-capping response to a blowout at surface is described in Figure 1-15.

In addition, BPXA certifies that it maintains a separate well blowout contingency plan applicable for Endicott and Badami that is not part of this plan. It will be made available to ADEC upon request for inspection as stipulated by 18 AAC 75.425(e)(1)(I), .445(d)(2) and .480.

1.9.2 RESPONSE SCENARIOS FOR WELL BLOWOUTS

As a preventive measure, Endicott operations prohibit the drilling of new wells or sidetracks from existing wells into major liquid hydrocarbon zones at its drill sites during the defined periods of broken ice. The first period begins June 1 and ends July 20. The second period begins October 1 and ends with 18 inches of continuous ice cover for 0.5 mile in all directions from the MPI and SDI.

Operations will present reservoir information to the AOGCC for an AOGCC determination of which stratigraphic zones represent major liquid hydrocarbon accumulations. The AOGCC determination will be submitted to ADEC for concurrence and approval of broken ice drilling programs. The purpose of the drilling moratorium is to eliminate the environmental risk associated with a well blowout to the Beaufort Sea during broken ice conditions.

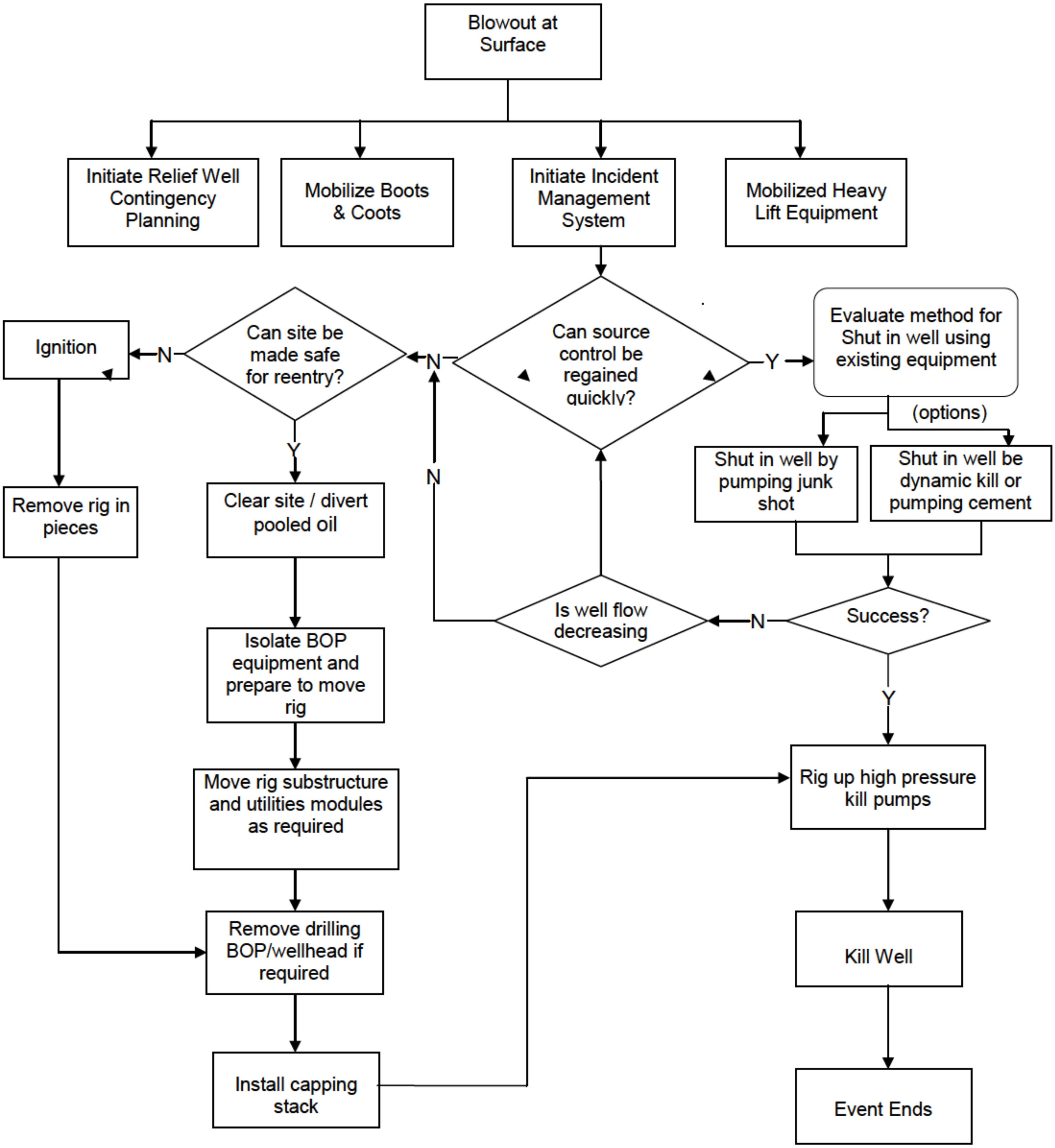
Drilling restrictions do not apply the rest of the year. Section 1.6.4 shows that the well blowout response planning standards are met in winter conditions of fast sea ice and under summer conditions of less than one-tenth sea ice coverage.

TABLE 1-30: WELL FIREFIGHTING AND CAPPING EQUIPMENT LIST

COMPONENT	WELL CAPPING USAGE	LOCATION	MOBILIZATION & TRAVEL TIME TO ENDICOTT
Bulldozer	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
Backhoe	Drainage ditch, berm construction	North Slope	
Crane	Spotting support equipment	North Slope	
6,000 gallons per minute Fire Water Pumping	Fire and heat suppression	North Slope	
Athey Wagon	Tractorized booms for manipulation of tools in and around blowout well	North Slope	
500 ton Drilling Block	Block and tackle system for moving or dragging heavy equipment	North Slope	
Drilling Line	Component of block and tackle system if rig moving system is inoperable	North Slope	
20-inch and 30-inch Casing	Used to construct Venturi tubes to divert blowing well bore fluids (ignited and un-ignited).	North Slope	
Miscellaneous Equipment	High pressure chicksan, flexible hoses, valves, containment boom, absorbent, hand tools	North Slope	
Junk Shot Manifold	Manifold system constructed to pump small leak sealing materials into well	North Slope	
Hot Tap Tool	Manifold used to gain safe access to pressurized tubulars at surface	North Slope	
Crimping Tool	Sized device used to pinch tubulars closed to seal off internal flow	Houston, Texas	<48 hours
Abrasive Cutter	High pressure cutting tool used to sever leaking blowout preventers, rig structures	Duncan, Oklahoma	
Kill Pump	Back up to rig pumps	North Slope	≤10 days
Capping Stack	Various high pressure blowout preventer (BOP) stacks (to replace leaking, damaged or severed primary BOPs)	Houston, Texas	
Heavy Lift Helicopter	Helicopters capable of lifting 18,000 to 21,000-pound loads into remote or offshore locations	US Pacific Northwest	

Note: The timing assumes deliveries by air by means of a C-130 or other capable aircraft.

FIGURE 1-15: WELL CAPPING DECISION TREE



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

Part 2, Prevention Plan, is in Volume 2.

PART 3. SUPPLEMENTAL INFORMATION [18 AAC 75.425(e)(3)]

3.1 FACILITY DESCRIPTION AND OPERATIONAL OVERVIEW [18 AAC 75.425(e)(3)(A)]

See Volume 2, Prevention Plan.

3.2 RECEIVING ENVIRONMENT [18 AAC 75.425(e)(3)(B)]

The receiving environment consists of tundra and shorelines downslope of oil pipelines, wells and tanks, and of marine waters and shorelines of the Beaufort Sea.

3.2.1 POTENTIAL ROUTES OF DISCHARGES [18 AAC 75.425(e)(3)(B)(i)]

The Alaska Clean Seas (ACS) *Technical Manual,* Volume 2 Map Atlas maps and facility figures provided in Part 1.8 illustrate potential routes of travel of oil discharged from the facility to open water. ACS *Technical Manual*, Volume 2 Map Atlas Sheets 67, 73, 74, 78, 79, 80, 83, 86, 87, 89, 90 and 91, incorporated by reference, and the facility figures in Part 1.8 show pre-staged spill response equipment locations to facilitate quick equipment deployment in the event of a discharge. The maps also illustrate areas where containment boom is pre-deployed seasonally to prevent a discharge to open water. The scenarios in Part 1 illustrate containment sites and features, and identification and explanation of measures that will be taken to prevent a discharge from entering open water.

3.2.2 ESTIMATE OF RESPONSE PLANNING STANDARD (RPS) VOLUME TO REACH OPEN WATER [18 AAC 75.425(e)(3)(B)(ii)]

Refer to the scenarios in Part 1 for the simulated volumes calculated to reach open water. At Endicott, zero percent of the oil from the simulated winter blowout is expected to reach open water. Approximately thirty percent of the oil from the simulated summer blowout is expected to reach open water. Approximately forty percent of the oil released from the simulated rupture on the crude oil transmission pipeline could reach open water.

3.2.3 BROKEN ICE CONDITIONS AT BIG SKOOKUM BRIDGE, ENDICOTT CAUSEWAY

Data from various sources over the period 1973 to 1986 and 1996 to 1998 indicate that the average date when the Sagavanirktok River begins overflooding the sea ice off the delta is May 26, ± 5 days standard deviation. According to the Endicott Monitoring Program (SAIC 1991), the time between the beginning and end of overflood averages 13 days, corresponding to a typical end date for the peak overflood of June 8.

The overflood extent and timing play a major role in controlling the melt and decay patterns of ice in nearshore areas such as Simpson Lagoon adjacent to West Dock, and the shallow lagoon area south of the inter-island causeway to Endicott. While overflood almost always encompasses the ice on both sides of the breached causeway section leading to the Endicott Satellite Drilling Island (SDI), floodwaters from the Kuparuk River do not always reach as far east as West Dock. For example, in 1989 the area between West Dock and the end of Stump Island remained outside the flood boundary. This ice then melted naturally in situ without the accelerating effect of the overflood waters and sediment deposited on the ice surface following drainage. Sediments carried onto the ice by the floodwaters remain on the surface after the water levels subside. The sediments greatly accelerate the ice deterioration in lagoon areas by reducing the surface albedo.

The difference in the rate of disappearance of nearshore ice between flooded and non-flooded areas is significant. For example, in 1989 the pro delta inshore of the inter-island causeway to Endicott was almost completely ice-free by June 18. In contrast, that year the area between Stump Island and West Dock remained as rotting, consolidated fast ice until early July.

From this limited evidence, it can be concluded that the flooded bottom fast ice in the vicinity of the Endicott breached causeway south of SDI remains intact for about five days after the nominal end of the peak overflood, when the floating fast ice farther offshore drains (Atwater 1991). These observations agree with the findings reported by Atwater in documenting the detailed sequence of break-up events around the Endicott causeway in 1989.

In most years, the ice conditions in the vicinity of the Big Skookum bridge around mid-June ($\pm$ 5 days) are most likely a mix of open water holes, rotting small floes (in the order of 50 to 100 feet), and/or cakes of ice (tens of feet across by one foot thick) released from the bottom and melting rapidly in the warm, fresh river outflow. There could still be areas with some partly submerged or barely awash ice patches fast to the bottom in water depths around two to three feet. The remaining mobile ice cakes and brash tend to clump in patches or windrows and fetch-up (strand) on one of the north-south barriers, mainly the breached causeway leading to the SDI, or the remaining fast ice edge connecting the SDI and Point Brower. Any remaining ice at this time is heavily coated with sediment deposited from the overflood waters and the waters around the bridge are of very high turbidity.

The majority of the bottom fast ice remaining in mid-June is likely to persist north of the Big Skookum Bridge, along the south side of the main SDI-Main Production Island (MPI) causeway farthest from the immediate effects of the river discharge. A condition of true broken floating ice at the spill site is expected to be very short lived (several days). In 1989, the inner lagoon area off the Sagavanirktok River Delta went from flooded ten-tenths (100 percent coverage) first-year bottom fast ice, to close to open water within days. A June 16, 2000, image from Landsat 7 shows no mobile floes large enough to register on the satellite image in the nearshore Sagavanirktok River delta areas. However, there do appear to be areas of brown silt-laden bottom fast ice still persisting in patches immediately south of the main causeway. This condition is similar to the pattern reported for 1989.

Note that at the time when the rapid melt and clearing is taking place inshore of the main Endicott east-west causeway, the area to the north of the causeway is still characterized by ten-tenths fast ice. This ice normally remains intact throughout June and into early July. Open water in the offshore area north of Endicott typically occurs around the third week in July.

Summer ice incursions into the nearshore lagoon areas around Endicott are extremely unlikely. Moving broken ice in Stefansson Sound in July and August is effectively prevented from entering the nearshore areas for a number of reasons: (1) the causeway connecting the SDI and the MPI acts as an ice boom; (2) the force of the river discharge will tend to keep the ice off the inshore delta areas; and (3) the water depths inside the causeway are so shallow that almost all substantial pack ice floes will go aground before getting into the area.

Highly detailed observations were carried out to document the timing of break-up and freeze-up processes in 1989 at several points on the Endicott causeway and at West Dock and East Dock (Ref. Atwater for SAIC 1991 as part of the overall 1989 *Environmental Monitoring Program – Volume IV*). The 1989 data set included daily hand-held photographs of break-up with a full 180-degree panorama surrounding Big Skookum from June 7-21, 23-30 and into July. Atwater's report contains the most detailed available description of local ice conditions relevant to a pipeline rupture at Big Skookum inner causeway.

The sequences of events characterizing break-up in the immediate vicinity of Big Skookum Bridge in 1989 were as follows:

May 23	River channel "swelling" (immediate pre-flood condition).
May 29	First flooding of river water onto the sea ice (within standard deviation on the average historical date for onset of Sagavanirktok River flooding).
June 6	Floodwater drainage occurred, within a few days of the average (note, this date refers to an observation that drainage is complete beyond the two meter isobath even though water remains on the ice inside of the causeway).
June 9	Aerial survey shows that Big Skookum is still surrounded by flooded first-year ice (boundary between flooded and drained ice is at Little Skookum).
June 10	Ice conditions in the breaches themselves were 50 percent open water.
June 12	Ice was starting to break up around the breaches.
June 13	Little Skookum was choked with brash ice for a brief period.
June 15	There was open water from shore out to the north end of the Little Skookum breach, and the only ice left in the inner lagoon area was a strip of puddle ice along the inner side of the SDI-MPI causeway.
June 21	Inner lagoon inside the inter-island causeway was rated as open water.

There is no evidence that the 1989 break-up was particularly unusual in terms of the timing or progression of ice decay. The presence of mobile broken ice conditions in and around Big Skookum is a short-lived event in the order of a few days, or less, in most years.

3.3 COMMAND SYSTEM [18 AAC 75.425(e)(3)(C)]

The oil spill response command system is compatible with the Alaska Regional Response Team (ARRT) *Alaska Federal/State Preparedness Plan for Response to Oil and Hazardous Substance Discharges/Releases* (Unified Plan). The organizational structure is based on the National Incident Management System (NIMS). It provides clear definition of roles and lines of command, together with the flexibility for expansion or contraction of the organization. The BP Exploration (Alaska), Inc. (BPXA) Incident Management Team (IMT) through the leadership level is illustrated in Figure 1-2. Additional details of the BPXA management structure, including Incident Command System (ICS) positional roles and responsibilities, are provided in the BPXA Incident Management System (IMS) Manual.

In most Tier 1 incidents, the Spill Response Team (SRT) can control the incident. The Environmental Advisor fulfills the role of On-Scene Commander. The SRT steps down into the Operations Section and additional personnel become involved to fill support roles.

Tier II/III responses are initiated by the On-Scene Commander. The IMT is activated and begins to provide support to the field responders (Operations Section) and coordinate the collection and distribution of information. ACS provides personnel and equipment resources from Deadhorse to assist in spill containment and recovery. The BPXA Business Support Team may be activated to provide additional support to the IMT.

ACS will be activated to stand by for spills until an assessment is performed. Once the assessment is complete, ACS is either released or mobilized. The North Slope operators coordinate with ACS to ensure a reserve of trained personnel is available for an extended spill response.

The North Slope operators view Unified Command as a structure that is created at the time of an incident to bring together the Incident Commanders of each major organization involved in response operations. For the North Slope Subarea, the Unified Command is typically comprised of the Federal On-Scene Coordinator (FOSC), the State On-Scene Coordinator (SOSC), the Local On-Scene Coordinator (LOSC), and the Responsible Party Incident Commander (RPIC). The North Slope Borough is the LOSC.

The primary responsibilities of the Unified Commanders are as follows:

- Establish objectives and priorities,
- Review and approve tactical plans developed to address objectives and priorities,
- Ensure the full integration of response resources, and
- Resolve conflicts.

These responsibilities are typically exercised through periodic, highly-focused Unified Command meetings with attendance typically restricted to Unified Command members.

The role of the agency representatives on the Unified Command is to fulfill their legal responsibilities (i.e., to direct and/or monitor response operations), while allowing the Responsible Party to manage emergency response operations.

When an incident occurs, the Unified Command structure may be established and superimposed at the top of the IMT. In this position, the On-Scene Coordinators are ideally situated to carry out the responsibilities cited above. They provide overall direction by establishing strategic objectives and response priorities addressed by the IMT through the planning process. Moreover, they review and approve the products of the planning process (i.e., Incident Action Plans) developed by the IMT to address the objectives and priorities.

The Unified Command position at the top of the IMT also facilitates the appropriate integration of response resources. For the agency representatives, it allows them to determine the appropriate role(s) for agency personnel and to position them optimally within the IMT structure. For the Responsible Party, it ensures members of the IMT have access to valuable expertise without diluting their ability to manage response operations.

3.4 REALISTIC MAXIMUM RESPONSE OPERATING LIMITATIONS [18 AAC 75.425(e)(3)(D)]

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 the 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 Alaska Administrative Code (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.

Additional specific response measures may be taken to reduce the environmental consequences of a spill when environmental conditions exceed operating limits. In high wind-chill situations more staff may be added to allow longer break times. Where ground visibility or road transportation is limited by weather, conditions aloft may allow flights for transportation and surveillance. Tracked vehicles and airboats can transit meltwater, snow and ice surfaces that preclude wheeled traffic. In sea states that preclude oil containment and recovery, vessels are still able to transit. When night hours otherwise restrict visibility, light plants can be brought into play.

This section describes additional specific response measures that will be taken to reduce the environmental consequences of an oil spill to ice conditions.

3.4.2 WEATHER AND ICE CONDITIONS DURING THE SHOULDER SEASONS

The following general description of break-up and freeze-up describes typical marine conditions in the Prudhoe Bay region. They cover the chronology of break-up and freeze-up. See 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 analysis. See DF Dickins Associates et al. (2001) for descriptions of seasonal ice conditions.

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 one 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 melt water pools (Condition 6).

Air temperatures average 35 degrees Fahrenheit (°F) and range from 20 to 40 °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 7 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

Oct 4, ±8 days: Freeze-up begins along shore in shallow water. Ice becomes shore fast for the season within 1 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 being able to commence on-ice operations with response equipment ranges on average from 40 to 43 days at coastal or nearshore locations such as Point McIntyre 1, Niakuk, and Endicott, to 55 days at the Northstar.

Air temperatures at freeze-up range from 5 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

Oil spill removal during the shoulder seasons can be greatly enhanced by in situ burning. Cold water and ice provide containment, and slow the weathering process, thereby 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* describes 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 the plan.

- B-1 In Situ Burning Plan
- B-2 Burning Oily Vegetation
- 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
- 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 described in the ACS *Technical Manual* several times a year at North Slope locations. 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 Pipeline Service Company (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 3-1.

TABLE 3-1: BURNING EQUIPMENT

EQUIPMENT	QUANTITY
Helitorch	8
Helitorch Surefire gel	1,200 pounds
Air deployable igniters	1,480
Helitorch batch gel mixers	2

Adopted from ACS inventory – Response Equipment Specifications, ACS *Technical Manual*, Tactic L-6

In addition, ACS maintains over 18,000 feet of fire-resistant boom ranging in overall height from 20 to 30 inches, together with specialized logistics vehicles to access spill sites over a rotting and/or flooded ice surface in May and June (e.g., airboats). See Tactic L-6 tables describing boom and vessels.

Once state and federal approval is 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.

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 that 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. 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. A detailed discussion of the determination of safety distances can be found in Chapter 3 of the “In Situ Burning Guidelines for Alaska, Revision 1” (ADEC, U.S. Environmental Protection Agency [EPA] and U.S. Coast Guard [USCG], March 2008).

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, Sørstrøm et al. 2010) and a few large field tests (Singsaas et al. 1994 and Sørstrøm et al. 2010). 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 that the efficacy of in situ burning is sensitive to ice concentration and dynamics Important variables include 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 6/10 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 scientific principles and physical processes involved 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 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 3-2.

TABLE 3-2: MINIMUM IGNITABLE THICKNESS ON WATER
Adapted from Buist Et Al. (2003)

OIL TYPE	MINIMUM THICKNESS
Light Crude and Gasoline	1 millimeter (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 a burning consumption rate of 3.5 millimeters per minute (mm/min). Lighter fuels burn faster, and heavier oils and emulsions burn slower, as shown in Table 3-3.

TABLE 3-3: BURN/REMOVAL RATES FOR LARGE FIRES ON WATER
Adapted from Buist et al. (2003)

OIL TYPE/CONDITION	BURN/REMOVAL RATE
Gasoline >10 mm (0.4 inch) thick	4.5 mm/min (0.18 inch per minute - 0.18 in/min)
Distillate Fuels (diesel and kerosene) >10 mm (0.4 inch) 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[1]	90 percent of rate stated above
Slick 2 mm thick[1]	50 percent of rate stated above
Emulsified oil (percent of water content)[2]	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.	

[1] Thin slicks will naturally extinguish, so this reduction in burn rate only applies at the end of a burn.

[2] 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).

Burn rate is also a function of the size of the fire. Crude oil burn rates increase from 1 mm/min with 3-foot diameter fires to 3.5 mm/min for 15-foot fires and greater. In situ burns on melt pools typically consume oil at 1 mm/min. 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/min. As fire size grows to the 50-foot range, oil type ceases to affect burn rate for the same reason.

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 3-4. 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 3-4: FIRE EXTINGUISHING SLICK THICKNESS
Adapted from Buist et al. (2003)

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.

Oil thickness is maintained by water current 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 that 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, Revision 1” (ADEC, EPA, and USCG, March 2008) state:

"In general, however, the effects [biological effects of burn residues] are less severe than those from a large, uncontained oil spill, and no specific biological concerns have been identified to date (ASTM, 2003)." 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 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 initially 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;
- Zero burn efficiency for emulsion slicks having water contents of 25 percent or more; and
- Some crudes form meso-stable emulsions that can burn efficiently at much higher water contents. Paraffinic crudes appear to fall into this category.

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 weathered 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 appears 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 (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);
- The oil is not more than 25 percent emulsified; and
- Herding in a current and enlarging fire diameters can increase burning rates.

3.5 LOGISTICAL SUPPORT [18 AAC 75.425(e)(3)(E)]

BPXA 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. BPXA has contracts for operational logistical support to support a spill response.

ACS *Technical Manual* Tactics L-3, L-4, 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

Contracted or other oil discharge containment, control, cleanup, storage, transfer, lightering, and related response equipment to meet the applicable response planning standard in Part 1 and to protect environmentally sensitive areas and areas of public concern identified in Part 3 and that may be reasonably expected to suffer an impact from a spill of the response planning standard volume as described in Part 1 is listed as required by 18 AAC 75.425(e)(3)(F)(i) to (vii). The location, inventory and ownership of ACS-managed equipment listed in the response planning standard scenarios in Part 1 is listed in the ACS *Technical Manual*, Tactic L-6, and in the *Technical Manual*'s tactics descriptions incorporated by reference in the scenarios in Part 1. The time frame for delivery and startup of response equipment and trained personnel located outside the North Slope is outlined in the response scenarios in Part 1. The manufacturer's rated capacities, limitations and operational characteristics for each item of oil recovery equipment listed in the scenarios in Part 1. The manufacturer's rated capacities, limitations and operational characteristics for the oil recovery equipment listed in the scenarios in Part 1 are also described in the ACS *Technical Manual*, Tactic L-6. Each vessel and the equipment for transferring oil from tanks mentioned in the scenarios in Part 1 is listed in Tactic L-6 as well.

3.6.2 MAINTENANCE AND INSPECTION OF RESPONSE EQUIPMENT

Response equipment is maintained so that it can be deployed rapidly and in condition for immediate use. The on-site response equipment is routinely inspected and tested by ACS. In addition, ACS performs routine maintenance of its response equipment. Inspections, tests and maintenance follow ACS written standard operating procedures.

ACS holds Oil Spill Removal Organization (OSRO) classifications for facilities and vessels. ACS has fulfilled the equipment maintenance and testing criteria that the classifications require.

3.6.3 PRE-DEPLOYED AND PRE-STAGED EQUIPMENT

The general spill prevention and response plan includes boom pre-deployment and the staging of spill response equipment at selected areas. SRT personnel deploy diversionary and exclusion boom in rivers each summer season. With each year's experience in operating in rivers, the staging of equipment and sites has varied. The goal is to strategically locate the staged equipment in proximity to potential leak sources, and in areas that are easily accessible, allowing for the quick deployment of additional equipment if needed. Gravel pads near the rivers can be used as additional staging areas. Additional boom deployment sites, boat launches, and staging areas are evaluated annually.

Due to seasonal changes of the river channels and weather conditions causing fluctuating river currents, specific boom-laying configurations, and exact footage lengths of boom prestaged at each site vary. At each prestaging site, boom sections and anchors are staged on the shoreline in a manner that optimizes its intended use for containment and recovery.

The open water timeframe for 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. It is anticipated that the initial boom pre-deployment at each site will take approximately two weeks. Prior to fall freeze-up, associated spill response equipment will be removed from the river, cleaned and repaired, returned to the connex staging boxes, and the boat launch ramp removed from the river systems.

The type of boom and anchor used at pre-deployment sites depends on such factors as water speed and depth. A variety of boom is stocked on the slope at storage facilities, from 4-inch swift-water boom to 20-inch diameter containment boom. Due to seasonal changes of the river channels and weather conditions causing fluctuating river currents, specific boom-laying configurations and exact footage lengths of boom pre-deployed at each site vary. At each pre-deployment site, sufficient boom sections and anchors are used to traverse the water body in a manner that optimizes their intended use of containment and recovery

Pre-staged equipment is described in the ACS *Technical Manual,* Volume 2, Sheets 67, 73, 74, 79, 83, 86 and 89 are incorporated here by reference. The staging area for the Sagavanirktok River is the boat ramp at the eastern Greater Prudhoe Bay (GPB) fire training grounds.

3.7 NON-MECHANICAL RESPONSE INFORMATION [18 AAC 75.425(e)(3)(G)]

In situ burning equipment inventory and deployment is described in the ACS *Technical Manual* Tactics L-6 and B-2 through B-7, which are incorporated here by reference.

Crude oils exhibit specific properties (SL Ross Environmental Research Ltd., 2006). A recent sample of Endicott oil's density ranges from 0.895 grams per cubic centimeter (g/cm^3), when fresh and at 15°C, to 0.932 g/cm^3 when evaporated to 15 volume percent loss and at a temperature of 1°C. At 1°C, its viscosity (measured at a shear rate of 180 s-1 using a Brookfield DV III+ Digital Rheometer) ranges from 60 milli Pascal seconds (mPa.s; 1 mPa.s is equivalent to 1 centiPoise [cP]) when fresh and at 15°C to 1,405 mPa.s when evaporated 15 percent and at 1°C. The pour point, determined by the American Society for Testing and Materials (ASTM) D-97 method, ranges from -3°C for fresh oil to 12°C for oil evaporated 15 percent. The flash point, measured using the Pensky-Martens Closed Cup Tester following ASTM D-93 methods, ranges from -2.5°C for fresh oil to 38°C for oil evaporated 15 percent. At freezing water temperatures Endicott crude is likely to form meso-stable water-in-oil emulsions in the presence of wave action with water contents in the 50 to 60 percent by volume range. At warmer temperatures (15°C), emulsification is unlikely with fresh Endicott, but the evaporated crude would likely form an entrained water emulsion (large water droplets temporarily entrained in the oil) with water contents in the 20 percent range.

Potter (2006) found weathered Endicott crude oil was fluid at 0°C and that ASTM D97's pour point is not a reliable predictor of the stored oil's tendency to flow at pump intakes.

Badami crude oil's density ranges from 0.876 g/cm^3, for fresh crude at 15°C, to 0.951 g/cm^3 when 34 volume percent evaporated and at 1°C. Its viscosity ranges from 18.5 mPa.s (at a shear rate of 180 s-1) when fresh and at 15°C, to 5,184 mPa.s (at a shear rate of 30 s-1) when evaporated 34 percent and at 1°C. The pour point ranges from -24°C for fresh oil to 3°C for oil evaporated 34 percent. The flash point is lower than -5°C when fresh and 112°C when evaporated 34 percent. Emulsification is unlikely for fresh Badami oil at freezing temperatures. Large water droplets can temporarily entrain in the oil to as much as 33 percent by volume in cold, evaporated oil. At 15°C, the oil is unlikely to emulsify.

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 agencies 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" (ADEC, EPA, USCG, 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” (ADEC, EPA and USCG, 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 concentrations at the ground diminish to limits established by National Ambient Air Quality Standards. The safe distance guidelines are based on the predictions of a National Institute of Standards and Technology, ALOFT-Flat Terrain model.

The safe distance meets the National Ambient Air Quality Standards for particulate matter over a 1-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 3-5 lists the general safe distances separating an in situ burn and downwind, populated areas in flat terrain.

TABLE 3-5: SAFE DISTANCES BETWEEN IN SITU BURNS AND DOWNWIND HUMAN POPULATIONS IN FLAT TERRAIN: LOCATION OF FIRE ZONES

<table>
<tr><th>LOCATION OF FIRE</th><th>GREEN ZONE</th><th>YELLOW ZONE</th><th>RED ZONE</th></tr>
<tr><td>Flat terrain on land</td><td rowspan="2">>3 miles</td><td rowspan="2">1 to 3 miles</td><td rowspan="2"><1 mile</td></tr>
<tr><td>Water <3 miles from shore</td></tr>
<tr><td>Water >3 miles from shore</td><td>>1 mile</td><td>Not applicable</td><td><1 mile</td></tr>
</table>

Burning at a green zone safe distance from the public is acceptable following public notification.

The “In Situ Burning Guidelines for Alaska Revision 1” (ADEC, EPA and USCG, 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 miles 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

3.7.2 OPERATIONAL CAPABILITY

ACS maintains specialized equipment to conduct in situ burning operations during all seasons and all ice conditions. The extensive inventory of response equipment is specifically designed to support a large scale burning operation. See Section 3.4.3, In Situ Burning Response Measures to Reduce Environmental Consequences of a Spill in Ice Conditions, for details.

3.7.3 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 SL Ross et al. 1998, DF Dickins et al. 2000, Sørstrøm et al. 2010). See Section 3.4.3, In Situ Burning Response Measures to Reduce Environmental Consequences of a Spill in Ice Conditions, for details.

3.8 RESPONSE CONTRACTOR INFORMATION [18 AAC 75.425(e)(3)(H)]

BPXA will activate ACS and the North Slope members of ACS to provide the initial manpower and resources for a large or lengthy spill response. The address and phone number for ACS is shown in Section 1. If additional resources are required, they will be accessed through Master Services Agreements maintained by ACS. BPXA's Statement of Contractual Terms with ACS is provided in the Introduction.

3.9 RESPONSE TRAINING AND DRILLS [18 AAC 75.425(e)(3)(I)]

3.9.1 NORTH SLOPE SPILL RESPONSE TEAM TRAINING

The North Slope Spill Response Team (NSSRT) consists of workers who volunteer as emergency spill response personnel. 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 physicals, and respiratory fit test are tracked by ACS through weekly reports from the database. At intervals not exceeding 15 months, but at least once each year, BPXA makes changes to its emergency response training program to maintain its effectiveness in compliance with 49 CFR 195.403(b). The NSSRT training program is provided to responders from all production units on the North Slope.

Response training and attendance is documented and available for review. The yearly training schedule is also available at the facility and ACS Base. Current NSSRT training schedules are posted on the ACS web site.

The minimum NSSRT staffing level on the North Slope is illustrated in Table 3-6. It represents the largest shift demand within the first 72 hours for each responder classification derived from the scenarios presented in Section 1.6. Responders are classified into five categories each with minimum training requirements as noted below.

TABLE 3-6: SPILL RESPONSE TEAM MINIMUM STAFFING LEVELS

RESPONDER CLASSIFICATION	NUMBER
General Technician	58
Skilled Technician	51
Team Leader	Included among vessel operators
Vessel Operator-Nearshore	10
Vessel Operator-Offshore	9
Total Responders	128

GENERAL TECHNICIAN

The General Technician is a responder with minimal or no field experience in spill response. Duties are associated with mobilization, deployment and support functions for the response. Support tasks such as deployment of boom sections, assembly of anchors systems, assembly of temporary storage devices, loading and unloading equipment, and decontamination of equipment are typical tasks undertaken by this responder classification. Responders in this classification must have a current 24 Hour (or higher) HAZWOPER Certificate.

Over time, the NSSRT training program brings NSSRT members from General Technician to at least the Skilled Technician level.

SKILLED TECHNICIAN

The Skilled Technician is a responder who has experience in spill response activities at a higher level through specific training, related activities as part of regular employment, or in spill response incidents. Tasks such as the operation of skimmers, power packs and transfer pumps are typical tasks undertaken by this responder. Responders in this classification have documentation of training as listed below:

- Minimum training requirements for the General Technician, and
- Completion of 16 hours of training or equivalent experience in any combination of the following categories:
    - Response equipment deployment and use;
    - Response tactics and equipment requirements;
    - Emergency response management (ICS);
    - Staging area management and support;
    - Boat safety, navigation, or operations; and
    - Contingency plan familiarization.
- Completion of 16 hours of actual spill response, response exercise, or field deployment time in any combination of the following positions:
    - Operation of recovery equipment systems;
    - Operation of transfer and storage equipment systems;
    - Deployment and use of containment systems;
    - Decontamination procedures;
    - Wildlife hazing, capture and stabilization; and
- Ten completed equipment proficiency checks.

TEAM LEADER

Team Leader roles may include such categories as Task Force Leader, Containment or Recovery Site Team Leader or Staging Area Manager. A team leader is described as an individual who has attended additional training in the actions, responsibilities and tasks associated with managing portions of an incident. Responders in this classification have documentation of training as follows:

- Training requirements for the General Technician,
- Training requirements for the Skilled Technician,
- Current 8-hour (or higher) HAZWOPER Supervisor Certification, and
- Twenty completed equipment proficiency checks.

VESSEL OPERATOR-NEARSHORE

Responders qualified as Vessel Operator-Nearshore, are tasked with safe operation of vessels less than 30 feet in length. The vessels have a hull design and electronics primarily intended for operation in nearshore environments or occasionally, in conjunction with larger vessels, in an offshore response. Typical duties include, towing and placement of containment booms, setting and tending anchors and movement of equipment to remote sites. Responders in this classification have documentation of training as listed below:

- Training requirements for the General Technician, and
- Criteria for any one of the following categories:
  - Completion of the ACS, Captain and Crew or Boat Safety and Handling Training Programs;
  - Completion of 40 hours of equivalent training or experience on vessels smaller or greater than 30 feet, including navigation, charting, vessel electronics and docking and maneuvering procedures;
  - Current USCG Operator Uninspected Passenger Vessel, or higher license; and
- Completion of Nearshore Vessel proficiency check.

VESSEL OPERATOR-OFFSHORE

Responders qualified as Vessel Operator-Offshore are tasked with the safe operation of vessels larger than 30 feet in length. The vessels have a hull design and electronics capable of sustaining operations in an offshore environment. Typical duties include the towing of containment booms, working in conjunction with barge containment operations, towing mini barges, operating skimmers to recover oil, providing ice management support and providing logistical support to offshore operations. Responders in this classification have documentation of training as follows:

- Training requirements of the General Technician, and
- Criteria for any one of the following:
  - Completion of the ACS, Captain and Crew Training Program;

  - Completion of 40 hours of equivalent training or experience on vessels larger than 30 feet, including navigation, anchoring, vessel electronics and docking and maneuvering procedures; and
  - Current USCG 25 Ton Near Coastal or larger license; and
- Completion of Offshore Vessel proficiency check.

ACTIVE MEMBER REQUIREMENTS

NSSRT members must complete minimum annual training activities to be considered an active member of the NSSRT. The training requirements include 8-hour HAZWOPER refresher certification and plan review.

The NSSRT training program offers weekly classes at each field. The classes emphasize hands-on experience, field exercises and team-building drills. The courses are selected by the ACS Environmental Lead Technician in conjunction with field management and use BPXA, ACS and external training consultants. Table 3-7 lists typical NSSRT training courses. Many are divided by subject area and taught in the 2- or 3-hour time frame of an NSSRT meeting.

TABLE 3-7: 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
	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
	Arctic Cold Water Survival
VESSEL-RELATED	Airboat Operations
	Boat Safety and Handling
	Boom Deployment On Rivers
	Captain/Crewman Vessel Training
	Charting and Navigation
	Deckhand/Knot Tying
	River Response School
	Swiftwater Survival

3.9.2 INCIDENT MANAGEMENT TEAM MEMBER TRAINING

A description of the North Slope IMT training program is provided in the ACS *Technical Manual*, incorporated by reference. The training program is compliant with the National Incident Management System (NIMS), which is described in detail in the USCG Incident Management Handbook, COMDTPUB P3120.17A (available online at www.gpo.gov).

North Slope incident management system training is provided by ACS or other NIMS-Certified 300 and 400 level trainers and includes an introduction to new members of the IMT, basic, intermediate and advanced ICS training, as well as position-specific training. The program is designed to be provided in a progressive manner that leads personnel through the entire operational planning period for an incident. Table 3-8 provides a summary of the training modules. Current training schedules are available on the ACS website at http://www.alaskacleanseas.org/.

Tabletop exercises and drills test knowledge and competency of the system. As new training needs are identified, they are developed and incorporated into the ICS training program. Training records of NSSRT response team members and contractors are maintained and available for inspection at the ACS Base in Deadhorse.

BPXA trains its IMT members based in Anchorage, called the Alaska Response Team. BPXA maintains a database of the training courses taken by each employee. Training includes ICS overview, section-specific training, and tabletop drills. Records are kept for a minimum of three years or for the entire time that the employee is assigned responsibilities in this plan. The database provides a brief description of the course and the date completed. Current training status of employees is available upon request.

TABLE 3-8: NORTH SLOPE INCIDENT MANAGEMENT SYSTEM TRAINING MODULES

MODULE NUMBER	COURSE
ICS-100	Introduction to the Incident Command System
ICS-200	Basic Incident Command System
ICS-300	Intermediate Incident Command System
ICS-400	Advanced Incident Command System
ICS -236	Staging Area Manager Workshop
ICS-341	Incident Response Planning Workshop
ICS-342	Documentation Unit Leader Workshop
ICS-346	Situation Unit Leader Workshop
ICS-348	Resources Unit Leader Workshop
ACS-1	Plan Development Unit Leader Workshop
ACS-2	Tabletop Exercise
ACS-3	Integrated Field Deployment and IMT Tabletop Exercise

3.9.3 SPILL RESPONSE EXERCISES

BPXA has adopted the NPREP guidelines. Participation in the National Preparedness for Response Exercise Program (NPREP) and use of its guidelines ensure federal exercise requirements mandated by Oil Pollution Act of 1990 (OPA 90) are met.

Internal exercises are conducted within BPXA to test the components of this plan for response to a spill. Components tested through the exercise program are as follows:

- Quarterly Qualified Individual (QI) Notification Drills are conducted to ensure the QI is able to be reached on a 24-hour basis in a spill response emergency and carry out assigned duties.
- Annual Spill Management Team Tabletop Exercises are conducted to ensure personnel are familiar with the contents of this plan, including the Incident Command System, crisis response procedures, mitigating measures, notification telephone numbers and procedures, and individual roles in the response structure.
- Semi-Annual Equipment Deployment Exercises are conducted to ensure internal and contractor-operated response equipment is fully functional and can be deployed in an efficient and productive manner.
- A triennial exercise of entire plan is conducted.
- Government-Initiated unannounced exercises are conducted.

The North Slope Crisis Management/Emergency Response (CM/ER) Coordinator is responsible for ensuring that an internal unannounced exercise meeting NPREP requirements occurs annually. The Planning Section Chief is responsible for documenting actions taken during an actual event for NPREP credit if it involves one of the following: use of emergency procedures to mitigate or prevent a discharge or threat of a discharge, activation of the field IMT or deployment of spill response equipment.

With the exception of government-initiated unannounced exercises, the internal exercises are self-evaluated and self-certified. Documentation, including a description of the exercise, objectives met and results of evaluations, is maintained for a minimum of five years. Exercise documentation is in written form, signed by the ACS Environmental Lead Technician for each exercise, and available for review on request. The CM/ER Coordinator will be responsible for coordinating exercise documentation.

The North Slope CM/ER Coordinator and the ACS Environmental Lead Technician or designee is responsible for the scheduling, development and evaluation of oil spill response training programs and exercises and for ensuring that regulatory requirements are met.

External exercises involve efforts outside of BPXA to test the interaction between BPXA and the response community. The external exercises also test the plan and the coordination between BPXA and the response community. The response community comprises the OSRO (ACS); state, federal and local agencies; and local community representatives.

BPXA participates in an annual Mutual Aid Drill (MAD). In addition to actively participating in the MAD, federal, state and local agencies are involved in the development and evaluation of the drill. Components tested through the MAD exercise are as follows:

Organizational Design

- Notifications (includes training on 24-hour notifications and reporting to the National Response Center [NRC]),
- Staff mobilization, and
- 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, and
- Disposal of recovered product.

Response Support

- Communications,
- Transportation,
- Personnel support,
- Equipment maintenance and support,
- Procurement, and
- Documentation.

3.10 PROTECTION OF ENVIRONMENTALLY SENSITIVE AREAS [18 AAC 75.425(e)(3)(J)]

Endicott crude oil is a persistent product. Many of its aromatic hydrocarbon compounds are toxic to fish, wildlife, and humans at various exposures.

Priority protection sites, sensitivities, surface water flow directions, wildlife protection strategies, and natural resources are described in the ACS *Technical Manual* Map Atlas, Volume 2, and are subject to confirmation by the resource agencies.

Mapped predictions of oil spill trajectories provided in the scenarios in Part 1. The effect of seasonal conditions on the sensitivity of wildlife and areas to be given priority attention are depicted in "Information on Seasonal Sensitivities" and on Sheets 66, 67, 72, 73, 74, 79, 80, 84, 85 and 91, respectively, in ACS *Technical Manual*, Volume 2

On a regional scale, environmentally sensitive areas are incorporated by reference from the North Slope Subarea Contingency Plan. The maps include (but are not limited to): geographic response strategy (GRS) sites, biologically sensitive areas, Most Environmentally Sensitive Areas (MESA), and the Environmental Sensitivity Index (ESI). The most current maps can be accessed at the following link:

http://www.asgdc.state.ak.us/maps/cplans/subareas.html#northslope

3.11 ADDITIONAL INFORMATION [18 AAC 75.425(e)(3)(K)]

Not applicable.

3.12 BIBLIOGRAPHY [18 AAC 75.425(e)(3)(L)]

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PART 4. BEST AVAILABLE TECHNOLOGY [18 AAC 75.425(e)(4)]

Part 4 addresses best available technology (BAT) requirements in 18 Alaska Administrative Code (AAC) 75.425(e)(4)(A), (B), and (C). This part also addresses technologies not subject to response planning standards or performance standards in 18 AAC 75.445(k)(1) and (2). The discussion of each technology complies with the requirement to analyze applicable technologies and to provide justification that the technology is the best available.

4.1 COMMUNICATIONS [18 AAC 75.425(e)(4)(A)(i)]

The communications system for use in a spill response is described in the Alaska Clean Seas (ACS) *Technical Manual*, Volume 1, Tactic L-11, incorporated here by reference.

4.2 SOURCE CONTROL [18 AAC 75.425(e)(4)(A)(i)]

4.2.1 WELL SOURCE CONTROL

The two methods of regaining well control once an incident has escalated to a surface blowout scenario described in Part 1 are well capping and relief well drilling. BP Exploration (Alaska) Inc. (BPXA) investigations indicate that well capping constitutes the BAT for source control of a blowout.

WELL CAPPING

Well capping techniques have proven efficient and effective in regaining well control and reducing environmental impacts. BPXA conducted a thorough investigation of well capping to regain control of a well blowout. The investigation used the response planning standard (RPS) conditions for exploration or production drilling as the evaluation case. Inherent in this evaluation were the assumptions that 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 assessment considered best available techniques and methods to control a deep well blowout with the potential of releasing liquid hydrocarbons at surface.

Well capping response operations are highly dependent on the severity of the well control situation. BPXA has the ability to move specialized personnel and equipment, e.g., capping stack or cutting tools, to North Slope locations upon declaration of a well control event. The materials to execute control, e.g., junk shots, hot tapping, freezing or crimping, are small enough that they can be quickly made available to remote locations, even by aircraft, as necessary.

BPXA has an inventory of well control firefighting equipment warehoused on the North Slope. This equipment includes two 6,000-gallon per minute (gpm) fire pumps, associated piping, lighting, transfer pumps, an Athey wagon, specialized nozzles and fire monitor shacks. The equipment represents a standard array of firefighting and well-control equipment normally mobilized by well control specialists in a blowout event. Maintaining this equipment on the North Slope significantly minimizes the time to mobilize and transport well control response equipment in an actual blowout event.

Other equipment for well capping operations are commonly available items on the North Slope (e.g., bulldozers, cranes, tanks, pumps, block and tackle, and large diameter casing). Mobilization of like equipment to Endicott in an emergency can be made available within a few hours after requests are submitted.

Well capping is both compatible and feasible with drilling operations because the technology is applied at the surface. There are no sensitivities to well types, (e.g., extended reach drilling, horizontal, or location). Well capping techniques have been applied both on land and at offshore locations and have historically proven successful in regaining well control within a short duration. Well capping techniques are preferred over the more time-consuming alternative of drilling a relief well. BPXA maintains an operating agreement with Boots and Coots Services, a worldwide well control specialist organization that can assist in the intervention and resolution of a well control emergency. This alliance of global service providers gives BPXA access to the best fit-for-purpose technology in response to a variety of emergency responses.

In an actual blowout event, well capping operations would commence with BPXA's activation of Boots and Coots Services and mobilization of key Incident Management Team (IMT) personnel, as well as deployment of select equipment. Dynamic and surface well control methods may continue in the interim only if it is approved and safe to do so. If the well capping option were selected and approved, safe re-entry to the wellhead area would be established and well capping operations would commence.

Other than the initial cost of the well control equipment currently stationed on the North Slope, maintaining an open contract with Boots and Coots Services is a minimal annual cost. Additional services required during an actual response would be provided at previously agreed upon rates.

The Bureau of Safety and Environmental Enforcement (BSEE) and SINTEF Civil and Environmental Engineering (Norway) data indicate that well capping technologies provide the shortest duration and most effective option for regaining well control and minimizing environmental impacts. This is seen in the more consistent application of well capping in response to well control events and the correspondingly shorter durations to successfully regain well control as compared to the few relief wells that have been attempted.

BPXA, in conjunction with well control experts from Boots and Coots Services, developed a schedule of events for conducting a well capping operation. This estimate does not take into account the high probability that well flow may be significantly reduced or stopped in the interim by formation bridging, dynamic kill operations, or surface well control actions. Forward plans require an iterative review process as well conditions change.

If involuntary ignition has not occurred, voluntary ignition of the blowout may also be considered as a method to reduce the volume of oil that falls to water or the surrounding tundra as well as reduce the potential of secondary explosive events in and around the rig complex. The decision of voluntary ignition must be a carefully considered option as it may result in an explosive event due to trapped compartmentalized gasses within the rig complex. Voluntary ignition with subsequent explosive events may impact safe access to the wellhead area, which may in turn alter response operations.

RELIEF WELL DRILLING

Relief well drilling technology is compatible to North Slope drilling operations although it may be sensitive to both the well location and well types. Multiple drilling rigs are under contract on the North Slope. Downhole and surface equipment (e.g., tubulars and wellheads) to support relief well drilling operations are also available. Relief well drilling is similar to current methods used to drill and complete North Slope wells today, and advances in directional drilling technology allowing more precise wellbore placement increase the likelihood of success of a relief well. However, relief well attempts would be more sensitive to blowout well locations or blowout well types for a facility having unique logistical challenges. For extended reach wells or remote locations with limited access, relief well drilling would be both challenging and time consuming.

Well control events where relief well drilling would be the preferred source control method involve events in which the potential to release liquid hydrocarbons to surface is highly unlikely, e.g., shallow gas, compromised surface casing or surface casing cement jobs, broaching or reasonable concern of broaching, inaccessible wellhead and/or casing. Government (Danenberger, 1993 and Izon, Danenberger, Mayes, 2007) and industry data (Scandpower A/S, 2001 and 2010) indicate that for a vast majority of the occurrences well control was regained through conventional dynamic kill procedures, surface control measures, well capping, or by natural means, e.g., formation bridging.

Optimum surface locations are rarely available on the North Slope and, as such, relief well drilling is often the least desirable option.

Relief well drilling to a deep zone blowout below surface casing can be a time-consuming and costly process. If access to the blowout location is unavailable, alternative locations must be sourced and/or constructed, e.g., access roads, gravel pads in the summer, or ice pads in the winter. After permitting, site construction, well planning, and rig mobilization, the relief well must still be drilled. Onshore North Slope relief well durations are often estimated in the 40- to 90-day range. These lengthy timelines add to the overall environmental impact (spill volume) of the blowout well. Based on historical data (Scandpower A/S, 2001), it is estimated that more than 97 percent of blowouts would be under control by other means by the time the relief well drilling rig could be mobilized.

Relief wells provide the longest duration alternative of effectively regaining well control. In addition to the longer blowout duration, the relief well itself introduces additional environmental risks. If access to a site near the blowout well is limited, a new gravel or ice site must be quickly constructed. If gravel is required there would be an impact to the tundra where gravel is placed. During equipment mobilization or relief well drilling operations, additional risks of spills and tundra impacts are possible. During the drilling of the relief well itself, the risk for a second well control event is introduced.

BPXA believes well capping constitutes BAT for well source control. In the event of a blowout BPXA deems it prudent to also activate a separate team to pursue a relief well plan parallel and independent of the primary well capping plan. This action is to ensure an alternate plan is being formulated and maturing for quick implementation if required. Table 4-1 summarizes well capping as BAT. Historical evidence clearly indicates well capping has greater reliability and application for well blowout control compared to that of relief well drilling.

TABLE 4-1: BEST AVAILABLE TECHNOLOGY ANALYSIS, WELL BLOWOUT SOURCE CONTROL

BAT EVALUATION CRITERIA	CURRENT 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 a few days.	Relief well drilling equipment (rigs, downhole tools, etc.) is available, though not widely used. If extended reach drilling (ERD) is required to intercept the affected wellbore rig selections become limited.
TRANSFERABILITY: Whether each technology is transferable to applicant's operations	Equipment is currently available on North Slope or on retainer via Boots and Coots Services contract.	Multiple drilling rigs are currently under contract and current rig sharing agreement has been signed by North Slope operators.
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, etc.) well capping is most frequent blowout control measure. Application of well capping provides 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 this technique. Relief well drilling at 40 to 90 days is the longest pollution mitigation measure possible. Relief wells may be preferred response method in some well control events (shallow gas, compromised surface casing or surface casing cementing, broaching, etc.), but these events are highly unl kely 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 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 and complete North Slope wells. Potentially sensitive to blowout well types (ERD) and location.
COMPATIBILITY: Whether each technology is compatible with existing operations and technologies in use by the applicant	Technology is compatible and applied at surface (no sensitivity to well type).	Technology is compatible though potentially sensitive to blowout well types (ERD, remote locations, etc.). Survey uncertainty on high departure wells may result in problems intersecting target wellbore.

TABLE 4-1 (CONTINUED): BEST AVAILABLE TECHNOLOGY ANALYSIS, WELL BLOWOUT SOURCE CONTROL

BAT EVALUATION CRITERIA	CURRENT 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 feasible 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 feasibility contingent upon geographical access near area of blowout. Lack of year-round access to some locations (offshore Beaufort) limits application. Very little evidence of successful application of relief well drilling as the primary mitigation measure of control. Relief wells may be preferred response method in some well control events (shallow gas, compromised surf casing or surf casing cementing, broaching, etc.), but these events are highly unl kely 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 is significantly less than conventional alternative technologies. Impacted area is localized to the affected well site and surrounding area.	Technology provides additional exposure and environmental risks during application (additional well control problems). Technology application may be seasonally limited, leading to durations of 60 to 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.

4.2.2 CRUDE OIL TRANSMISSION PIPELINE SOURCE CONTROL

Each sales oil line is fitted with pipeline isolation valves. Manual and automated valves are assigned at (b) (7)(F) [redacted] occur. This combination of valving is considered BAT. See Table 4-2.

TABLE 4-2: BEST AVAILABLE TECHNOLOGY ANALYSIS, CRUDE OIL TRANSMISSION PIPELINE SOURCE CONTROL

(b) (7)(F)

BAT EVALUATION CRITERIA	[redacted]	ALTERNATE METHOD: VERTICAL LOOPS
AVAILABILITY: Whether technology is best for use in other similar situations or is available for use by applicant		Available and in-place within Greater Prudhoe Bay.
TRANSFERABILITY: Whether each technology is transferable to applicant's operations		This technology is potentially transferable.
EFFECTIVENESS: Whether there is a reasonable expectation each technology will provide increased spill prevention or other environmental benefits		Vertical loops can provide an effective means to reduce spill volumes by creating drainage breaks.
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.		Approximate cost is $500K to 1.5 million. The cost of maintenance would be less than using valves.
AGE AND CONDITION: The age and condition of technology in use by the applicant		This would be a new installation.
COMPATIBILITY: Whether each technology is compatible with existing operations and technologies in use by the applicant		Compatible but would have to be engineered to ensure expansion and forces are within acceptable limits.
FEASIBILITY: The practical feasibility of each technology in terms of engineering and other operational aspects		Feas ble, but automatic or manual block valves are in place.

TABLE 4-2 (CONTINUED): BEST AVAILABLE TECHNOLOGY ANALYSIS, CRUDE OIL TRANSMISSION PIPELINE SOURCE CONTROL

BAT EVALUATION CRITERIA	(b) (7)(F) [redacted]	ALTERNATE METHOD: VERTICAL LOOPS
ENVIRONMENTAL IMPACTS: Whether other environmental impacts of each technology, such as air, land, water pollution, and energy requirements offset any anticipated environmental benefits	[redacted]	Potential environmental impacts due to new construction.

4.2.3 TANK SOURCE CONTROL

The tank source control BAT review is provided in Table 4-3. 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 whose levels are constantly changing. 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.

Manual valves are used on oil storage tanks that are filled infrequently. These tanks are subject to BPXA tank filling standard operating procedures requiring the presence of an operator during filling operations. Tank spill root-cause analysis by BPXA 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 such tanks.

TABLE 4-3: BEST AVAILABLE TECHNOLOGY ANALYSIS, TANK SOURCE CONTROL

BAT EVALUATION CRITERIA	(b) (7)(F) [redacted]	**ALTERNATE METHOD: AUTOMATIC VALVE CLOSURE**
AVAILABILITY: Whether technology is best in use in other similar situations or is available for use by applicant	[redacted]	Technology is available.
TRANSFERABILITY: Whether each technology is transferable to applicant's operations	[redacted]	Transferable
EFFECTIVENESS: Whether there is a reasonable expectation each technology will provide increased spill prevention or other environmental benefits	[redacted]	Additional automation would afford little benefit given the existing filling procedures and requirement for continuous on-site presence of operator during fill operation.
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.	[redacted]	Automation of this valve would cost $15,000 - 20,000 over the base case. We would still require the operator be at the fill site to oversee the fill operation.
AGE AND CONDITION: The age and condition of technology in use by the applicant	[redacted]	Method is more complex and current.
COMPATIBILITY: Whether each technology is compatible with existing operations and technologies in use by the applicant	[redacted]	Method is compatible.
FEASIBILITY: The practical feasibility of each technology in terms of engineering and other operational aspects	[redacted]	Method is feasible.
ENVIRONMENTAL IMPACTS: Whether other environmental impacts of each technology, such as air, land, water pollution, and energy requirements offset any anticipated environmental benefits	[redacted]	There are no offsetting environmental impacts.

4.3 TRAJECTORY ANALYSES AND FORECASTS [18 AAC 75.425(e)(4)(A)(i)]

Trajectory analyses and forecasts are described in the ACS *Technical Manual,* Tactics T-1 to T-6 and L-11, which are incorporated here by reference.

In the event of a spill, trajectory models will be based on observed and modeled currents, wind speed and direction, and observed oil tracking data. Vector addition and trajectory modeling are used to forecast oil movement on a real-time basis.

Several research and development programs are improving industry's capability to track environmental conditions real time. An industry- and agency-funded program is developing the capability of measuring ocean current speed and direction using high frequency radar. In 2009, the data was available real-time via the internet (Weingartner, 2010).

Under certain conditions, satellite-based Synthetic Aperture Radar (SAR) could be used to track large slicks on water in very open ice cover (<4/10). The current generation of all-weather SAR satellites can resolve targets to 1 meter resolution or less independent of cloud cover or light conditions. Consequently, SAR can play a valuable role in mapping detailed ice conditions and directing marine resources safely and efficiently (Sørstrøm et al., 2010). Existing commercial ground penetrating radar (GPR) systems can be used to detect oil trapped under snow on the ice and to detect oil trapped under solid ice (Sørstrøm et al., 2010.

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,* Volume, Tactics W-1 to W-3, W-5, W-6 and L-11, which are incorporated here by reference. The wildlife protection strategies are based on the *Wildlife Protection Guidelines for Alaska* (Annex G of the Alaska Regional Response Team Unified Plan).

See Volume 2 (Prevention Plan) for BAT analyses pertaining to:

- Section 4.5 – Cathodic Protection for Field-Constructed Oil Storage Tanks
- Section 4.6 – Leak Detection System for Field-Constructed Oil Storage Tanks
- Section 4.7 – Liquid Level Determination for Oil Storage Tanks
- Section 4.8 – Maintenance Practices for Buried Metallic Facility Oil Piping – Protective Coating and Cathodic Protection
- Section 4.9 – Maintenance Practices for Buried Facility Oil Piping – Corrosion Surveys
- Section 4.10 – Leak Detection for Crude Oil Transmission Pipeline

PART 5. RESPONSE PLANNING STANDARD [18 AAC 75.425(e)(5)]

Calculations of the applicable response planning standards set out in 18 Alaska Administrative Code (AAC) 75.432, .434, and .436, including a detailed basis for the calculation reductions to be applied to the response planning standards, are presented below.

5.1 OIL STORAGE TANK [18 AAC 75.432]

The adjusted response planning standard (RPS) volume for Endicott's wastewater storage tank, T-E3-

(b) (7)(F)

[redacted]

Tank T-E3-1802 has an overflow pipe that drains to the secondary containment pit located approximately 400 feet west of the tank. A 4-inch lip around the tank provides containment for small spills. In the case of an instantaneous rapture, the tank contents are assumed to spill over the lip.

5.2 WELL BLOWOUT [18 AAC 75.434]

The RPS volume for a production well blowout is 12,855 barrels. It is based on the highest average daily production of production wells at Endicott as reported by the Alaska Oil and Gas Conservation Commission (AOGCC). The average daily production at well 4-10A/L28 is 857 barrels of oil per day (bopd) x 15 days = 12,855 bbl. The daily discharge rate reflects the average annual daily production volume for the maximum oil producing well at Endicott in 2010, based on data available through the AOGCC. Although well 4-10A/L28 used gas lift for 9 months during 2010, BPXA is simulating a 15-day blowout.

At ADEC's direction, the RPS oil volume is not adjusted for portions that are predicted by S.L. Ross Environmental Research, Ltd., to remain aloft and not enter receiving environments of land and water surfaces.

5.3 CRUDE OIL TRANSMISSION PIPELINE [18 AAC 75.436]

An analysis of the crude oil transmission pipeline (COTP) was conducted in order to determine the greatest possible discharge that could occur, The initial RPS volume is calculated using the equation from 18 AAC 75.436 [redacted])]

Where,

L = pipeline length between pumping or receiving station valves

H = pipeline hydraulic characteristics due to terrain profile

C = pipeline capacity in barrels per linear measure

FR = pipeline flow rate in barrels per time period

TD = estimated time to detect a spill event

TSD = time needed to shut down the pipeline pump or system

The H value is based on a topographic divide that would prevent oil from flowing upgradient in an un-pressurized pipeline. The topographic divide is considered a segment of pipe with at least seven feet of elevation change. Seven feet equals an estimated average pipeline diameter plus five feet of pipeline elevation change. Assuming gravity drainage of oil from a de-pressurized pipeline, the seven-foot elevation difference provides a conservative estimate of the terrain profile that would prevent oil flow between segments.

In the event of a catastrophic break on the COTP at the point where it crosses underneath the Endicott causeway, approximately [redacted] feet of pipe would drain. The distance between the highest point, the Module 303 pig launcher, and the next highest point on the pipeline, a point 500 feet north of the valve at the north side of Resolution Bridge, is [redacted] lineal feet. The pipeline between these points would not drain. (See Figure 5-1.)

The time to detect a spill is 30 minutes. This time frame includes receiving an alarm from the crude oil transmission pipeline leak detection system and dispatching Security to the suspected leak location to verify a spill. From the time of spill verification, the time to shut down the COTP is 15 minutes.

[redacted]

(b) (7)(F)

[redacted]

FIGURE 5-1: ENDICOTT COTP ELEVATION PROFILE BETWEEN MPI AND THE VALVE AT RESOLUTION BRIDGE

(b) (7)(F)

[redacted]

FEDERAL

FACILITY RESPONSE PLANS

OPA 90 ADDENDUM

U.S. DEPARTMENT OF TRANSPORTATION
U.S. BUREAU OF SAFETY AND ENVIRONMENTAL ENFORCEMENT

Endicott facilities and Badami pipeline will be constructed, operated, and maintained in compliance with the terms and conditions of the U.S. Fish and Wildlife Service Letter of Authorization 06-02 regarding the incidental "take" of polar bears and walrus issued to BPXA on August 10, 2006.

U.S. DEPARTMENT OF TRANSPORTATION

ENDICOTT AND BADAMI UNITS
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**	
(a)	Identification of line sections that might cause significant and substantial harm to the environment in the event of a discharge	U.S. DOT Information Summary
194.105	**Worst case discharge**	
(a)	The worst case discharge and the methodology, including calculations, used to arrive at the volume	U.S. DOT Information Summary
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	Section 1.6.3
(b)	Certification that the response plan is consistent with the National Contingency Plan	U.S. DOT consistency certification
(c)(1)(i)	Information summary as required by 194.113	U.S. DOT Information Summary
(c)(1)(ii)	Immediate notification procedures	Sections 1.1, 1.2, 3.3
(c)(1)(iii)	Spill detection and mitigation procedures	Sections 1.6, 2.5, 4.2
(c)(1)(iv)	Name, address, and telephone number of oil spill response organization	Table 1-2
(c)(1)(v)	Response activities and response resources	Sections 1.1, 1.2, 1.6, 3.3, 3.6, 3.7, 3.8
(c)(1)(vi)	Names and telephone numbers of federal, state, and local agencies with pollution control responsibilities or support	Table 1-3
(c)(1)(vii)	Training procedures	Section 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, entire pipeline is a single-response zone
(c)(3)	Response management description	Section 3.3

Certification of Response Preparedness

BP EXPLORATION (ALASKA) INC.
ENDICOTT and BADAMI CRUDE OIL TRANSMISSION PIPELINE

Response Plans Officer
Pipeline and Hazardous Materials Safety Administration
U.S. Department of Transportation
400 Seventh Street, SW, Room 2103
Washington, DC 20590

BP Exploration (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.

Bruce Williams   7/23/2010

Mike Utsler   Date
for VP Operations
BP Exploration (Alaska) Inc.

This certification of Response Preparedness was acknowledged before me on July 23, 2010,
by ~~Mike Utsler~~ on behalf of said corporation.
Bruce Williams

LORRIE L. JORDHEIM
My Commission Expires
NOTARY PUBLIC
Mar. 20, 2012
STATE OF ALASKA

Lorrie Jordheim

3-20-12
Date commission expires

NCP / ACP Consistency Certification

BP EXPLORATION (ALASKA) INC.
ENDICOTT and BADAMI CRUDE OIL TRANSMISSION PIPELINE

BP Exploration (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 (ACPs) and found the Endicott/Badami Oil Discharge Prevention and Contingency Plan to be consistent with them. The NCP/ACPs reviewed include the NCP as set forth in 40 CFR 300, as published in 59 FR 47416, September 15, 1994 and the *Alaska Federal/State Preparedness Plan for Response to Oil and Hazardous Substance Discharge/Releases* (Unified Plan), Volume I and Volume II (North Slope Subarea Contingency Plan).

Mike Utsler	7/22/2010
for VP Operations	Date
BP Exploration (Alaska) Inc.	

U.S. DOT INFORMATION SUMMARY

Name and Address of Operator

BP Exploration (Alaska) Inc.
P.O. Box 196612
Anchorage, AK 99519-6612
Phone: (907) 564-5111

Street Address:
900 East Benson Boulevard
Anchorage, AK 99508
Fax: (907) 564-5180

Response Zone Description

BPXA's Endicott Unit consists of a single response zone containing the Endicott sales oil pipeline, which runs from the Main Production Island to Pump Station 1 of the Trans Alaska Pipeline System in the North Slope Borough of Alaska.

Badami is a single response zone containing the Badami sales oil line, which runs from the Badami production facility to the tie-in with the Endicott sales oil pipeline.

Name and Telephone Number of Qualified Individual

See Table 1-2 (BPXA Contact List) in the Endicott-Badami Oil Discharge Prevention and Contingency Plan for the name and telephone numbers of Qualified Individuals.

Worst-Case Discharge

In accordance with 49 CFR 194.105(b)(1), the worst-case discharge (WCD) for a 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 the 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 bbl or:

(b) (7)(F)

[redacted]

* The segment with the largest drainage volume on the Endicott pipeline is between the block valve upstream of the Badami tie-in and the first block valve east of the Sagavanirktok River (see Figure 1-26). The largest segment on the Badami pipeline is between the Shaviovik and Kadleroshilik River block valves (see Figure 1-31).

(b) (7)(F) [redacted]

Description of the Line Sections

The 16-inch diameter Endicott sales line carries North Slope crude oil aboveground for 26.5 miles between the Main Production Island and the Trans Alaska Pipeline System (Pump Station 1). The line has valves at the Main Production Island, on either side of Resolution Bridge, onshore near the causeway, on either side of the Sagavanirktok River, and at Pump Station 1 (see Figure 1-26).

The Badami sales line carries North Slope crude oil 25.1 miles between the Badami production facility and the Endicott tie-in. The 12-inch diameter pipeline runs aboveground except for buried sections at three river crossings. There area no road crossings. The line has multiple block valves and check valves as depicted in Figure 1-31.

Substantial Threat

Events and conditions that can pose a substantial threat of a WCD and procedures to eliminate or mitigate threat of a discharge are identified in the Endicott and Badami Sales Oil Pipeline *DOT Operations, Maintenance, and Emergency Response (OMER) Manual* (Section 3, Abnormal Operations).

Basis for Determination of Significant and Substantial Harm

The Endicott and Badami sales oil pipelines are expected to pose significant and substantial harm in the event of an oil spill. The Endicott pipeline lies within one mile of seabird concentration areas. The Badami pipeline crosses four rivers.

Certification of Response Personnel and Equipment

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

An Endicott sales oil pipeline spill response scenario is described in Scenario 4 of Section 1.6.3. Pre-staged spill response equipment is located along the pipeline, as shown in Figure 1-26. Table 1-24 shows there are sufficient resources to recover the WCD volume.

A Badami sales oil pipeline spill response scenario is described in Response Strategy 3 of Section 1.6.3. Pre-staged spill response equipment is located at three major river crossings: Shaviovik, Kadleroshilik and Sagavanirktok Rivers (see Figure 1-31).

Drinking Water and Camp Emergency Response

Oil Spill Fate and Transport (F&T) Analyses were conducted for BPXA crude oil transit pipelines in December 2006. The F&T Analyses for the crude oil transit pipelines showed that the maximum release volume from any individual location along the pipelines would not impact more than one drinking water source. Alternative drinking water sources are permitted and available in the areas where a drinking water high consequence area may be impacted.

The F&T Analyses also evaluated impacts to personnel camps, i.e., “other populated areas,” that may be affected by an aerosol discharge from the crude oil transit pipelines. Each facility on the North Slope, including personnel camps, has an emergency response plan which describes alarms, evacuation procedures and accountability. Additionally, the field Incident Management Team (IMT) would be mobilized immediately for significant events. The On-Scene Commander makes an initial evaluation of the magnitude of the incident and notifies potentially impacted facilities through the IMT. Should a personnel camp be a potentially impacted facility, they would monitor the incident and activate the facility emergency response plan as necessary.

Melanie M. C. Barber
United States Department of Transportation
Office of Pipeline Safety
Room E22-210
1200 New Jersey Avenue, S.E.
Washington, D.C. 20590

December 17, 2008

Ms. Eppie V. Hogan
Crisis Management Advisor
BP Exploration Alaska
P.O. Box 196612
Anchorage, AK 99519-6612

Dear Ms. Hogan:

I have approved four Facility Response Plans that BP Exploration Alaska submitted to the United States Department of Transportation Office of Pipeline Safety under the Oil Pollution Act of 1990: (1) Greater Prudhoe Bay, PHMSA Sequence Number 1742, (2) Milne Point Unit, PHMSA Sequence Number 404, (3) Endicott-Badami Operations, PHMSA Sequence Number 707, and (4) Northstar, PHMSA Sequence Number 1410.

Sincerely,

Melanie M. C. Barber

Melanie M. C. Barber
Environmental Planning Officer

U.S. BUREAU OF SAFETY AND ENVIRONMENTAL ENFORCEMENT (BSEE) (ENDICOTT ONLY)

ENDICOTT OPERATIONS
OIL DISCHARGE PREVENTION AND CONTINGENCY PLAN

CROSS REFERENCE TO
U.S. BUREAU OF SAFETY AND ENVIRONMENTAL ENFORCEMENT
RESPONSE PLAN REQUIREMENTS
[30 CFR 254, Subpart D]

REGULATION SECTION (30 CFR)	SECTION TITLE	PLAN SECTION
254.53	**Submitting a Response Plan Developed Under State Requirements**	
(a)	The plan must contain all the elements the State and OPA require and must:	
(1)	Be consistent with the requirements of the National Contingency Plan and appropriate Area Contingency Plan(s).	Volume 1, Introduction and Facility Response Plan , page DOT-3
(2)	Identify a qualified individual and require immediate communication between that person and appropriate Federal officials and response personnel if there is a spill.	Volume 1, Sections 1.1, 1.2, and 3.3
(3)	Identify any private personnel and equipment necessary to remove, to the maximum extent practicable, a worst-case discharge as defined in §254.47. The plan must provide proof of contractual services or other evidence of a contractual agreement with any OSRO's or spill management team members who are not employees of the owner or operator.	Volume 1, Sections 1.2, 1.6.4, 3.6, and 3.8 and this section of the Facility Response Plan
(4)	Describe the training, equipment, testing, periodic unannounced drills, and response actions of personnel at the facility to ensure both the safety of the facility and the mitigation or prevention of a discharge or the substantial threat of a discharge.	Volume 1, Section 3.9 and Volume 2, Section 2.1
(5)	Describe the procedures to periodically update and resubmit the plan for approval of each significant change.	Volume 1, Introduction
(b)	The plan developed under State requirements must also include the following information:	
(1)	A list of facilities and leases the plan covers and a map showing their location.	Volume 1, Introduction
(2)	A list of the types of oils handled, stored, or transported at the facility.	Volume 2, Sections 2.1.8 and 3.1, Tables 3-1 and 3-2
(3)	Name and address of the State agency to which the plan was submitted.	Volume 1, Introduction
(4)	The date the plan was submitted to the State.	Volume 1, Introduction
(5)	If the plan received formal approval, the name of the approving organization, the date of approval, and a copy of the State agency's approval letter, if issued.	Volume 1, Introduction
(6)	Identification of any regulation or standards used in preparing the plan.	Volume 1, Introduction and Facility Response Plan

Worst-Case Discharge Volume

(b) (7)(F)

[redacted]

REFERENCE
The total capacity of the oil storage tanks is the sum of permanent oil storage containers on Endicott Main Production Island (MPI). See Volume 2, Table 3-1 for capacities of individual storage tanks.
Flow line capacity specific to Endicott is calculated by the BP Exploration (Alaska), Inc. engineers. Endicott flow line capacity represents the sum of volumes from the headers and production well lines.
Catastrophic release volume from the sales oil pipeline is the sum of: 1) oil volume in the sales pipeline from MPI to the mainland landfall; and 2) an estimate of additional oil volume that would enter the pipeline from the production facility in the period before the break is detected and the valves shut.
The simulated blowout rate is based on highest capacity well associated with the facility (MPI 2-52), using reservoir characteristics, casing/production tubing sizes, historical production and reservoir pressure data.

Worst Case Discharge Response Scenario

The following scenario discusses a simulated response to a worst case discharge (WCD), including adverse weather conditions. The following WCD scenario is developed in accordance with 30 CFR 254.26. Table A-1 summarizes how the scenario meets the BSEE regulatory requirement. The table also provides references to documents that support the assumptions. The scenario is based upon assumptions about environmental conditions, oil distribution and response capabilities. The assumptions are supported by a number of publicly available technical documents.

The scenario describes equipment, personnel, and strategies that could be used to respond to an oil spill. The scenario is for illustration only. It is not a performance standard or a guarantee of performance. The scenario assumes conditions of the spill and responses only for the purpose of describing general procedures, strategies, and selected operational capacities.

Some details are examples. Although some equipment is named, it may be replaced by functionally similar equipment. The response timelines are for illustration only. They 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 for an effective response without jeopardizing safety.

Actual responses are determined by the Unified Command, and depend on safety considerations, weather, and other environmental conditions, agency permits, response priorities, and other factors. In any incident, consideration for personnel safety is the highest priority. The scenario assumes the agency on-scene coordinators and other agency officials immediately grant permits.

Larger responses than illustrated in the scenario can be mounted with additional in-region resources and with the mobilization of out-of-region resources.

WORST CASE DISCHARGE SCENARIO

WELL BLOWOUT DURING VARYING ICE CONDITIONS

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TABLE A-1: SUMMARY OF HOW THE SCENARIO COMPLIES WITH BSEE REGULATION

BSEE REGULATION	SUMMARY	REFERENCE
30 CFR 254.26 (a) and 254.47 (a) Worst Case Discharge Volume for Production Facility	(b) (7)(F) [redacted]	See the OPA 90 cross reference for descriptions of the basis of the WCD estimate. The estimates follow 30 CFR 254.47 regarding worst case discharges for production facilities. The total capacity of the oil storage tanks is the sum of permanent oil storage containers on Endicott Main Production Island. See Table 3-1 (Volume 2) for capacities of individual storage tanks. Flow line capacity specific to Endicott is calculated by the BP Exploration (Alaska) Inc. (BPXA) engineers. Endicott flow line capacity represents the sum of volumes from the headers and production well lines. Catastrophic release volume from the sales oil pipeline is the sum of: 1) oil volume in the sales pipeline from MPI to the mainland landfall; and 2) an estimate of additional oil volume that would enter the pipeline from the production facility in the period before the break is detected and the valves shut. Calculation is consistent with 18 AAC 75.436, which takes into account length, flow capacity, leak detection and shutdown time, and the effects of hydraulic characteristics due to the terrain profile and gravity. The simulated blowout rate is based on the daily production of well MPI 2-52. The simulated blowout rate is based on the reservoir characteristics (as defined by BSSE and 30 CFR 254.47(a)).

TABLE A-1 (CONTINUED): SUMMARY OF HOW THE SCENARIO COMPLIES WITH BSEE REGULATION

BSEE REGULATION	SUMMARY	REFERENCE
30 CFR 254.26(b) Oil Trajectory	A blowout at MPI would have an extremely high combustion efficiency due to the high gas to oil ratio. Although ignition would eliminate a large portion of the WCD, this scenario does not assume ignition. This scenario addresses the full volume calculated by the WCD blowout. The scenario assumes that the oil blows out to the atmosphere from a production well. In such a blowout, oil impingement on the well house is expected to reduce the oil's aerial plume and reduce its footprint beyond the rig. Available models do not account for the effect of impingement on the oil footprint dimensions. Consequently, the scenario calculates oil footprints by the Tactic T-6 model for an un-obstructed plume. Oil on open water, unaffected by ice, is assumed to move with surface currents and at 3 percent of the wind speed (see ACS *Technical Manual*, Tactic T-5). Because the data supporting our understanding of the effect of ice pieces on floating oil is minimal and complex, available trajectory models do not account for oil movement as a function of ice concentration.	For a discussion of the expected proportion of oil consumed by combustion, see SL Ross Environmental Research Ltd. and Energetex Engineering (1986). For data on oil evaporation, viscosity, and emulsification tendency, see SL Ross Environmental Research Ltd. (1994). The oil's aerial plume trajectory is based on ACS *Technical Manual*, Tactic T-6, a model developed by SL Ross Environmental Research Ltd., and incorporated into the scenario by reference. Portions of the ACS *Technical Manual* cited in the scenario are incorporated by reference. Wind direction is simulated as prescr bed by 18 AAC 75.425(e)(1). The wind data were retrieved from the Nearshore Beaufort Sea Meteorological Monitoring and Data Synthesis (Veltkamp and Wilcox, 2007) and subsequent data from a related project. The data represented in this scenario is summer-only data (May through October) collected from 2001 through 2011. The oil's trajectory on the sea is based on the following: 1. Historical water and ice movements described in Appendix H in SL Ross Environmental Research Ltd., DF Dickins Associates Ltd. and Vaudrey Associates, Inc. (1998). 2. Historical water and ice movements described in D.F. Dickins Associates Ltd., Vaudrey and Associates Inc. and SL Ross Environmental Research Limited. (2000).
30 CFR 254.26 (c) Important Resources	Resources of special economic or environmental importance that potentially could be impacted are the marine bird and mammal populations that occupy the sea between the pack ice and the shoreline and the shorelines of the barrier islands that lie in the oil trajectory. The trajectory is descr bed in the body of the scenario. The resources are described more fully in the references.	Resources of special economic or environmental importance that potentially could be impacted in the areas in the trajectory are described in the Alaska Regional Response Team's "North Slope Subarea Plan," Areas of Concern, which is also printed in the ACS *Technical Manual*, Volume 2, Map Atlas.
30 CFR 254.26 (d) (1) Response Equipment	The scenario identifies the types, numbers and usage of the equipment capable of containing and removing the oil.	The equipment's types, locations, owners, inventory quantity and capabilities are described in ACS *Technical Manual,* Volume 1, Tactics L-4 and L-6.

TABLE A-1 (CONTINUED): SUMMARY OF HOW THE SCENARIO COMPLIES WITH BSEE REGULATION

BSEE REGULATION	SUMMARY	REFERENCE
30 CFR 254.44 (a) Effective Daily Recovery Capacities	Unless stated otherwise, the effective daily recovery capacity of the skimmers are determined by multiplying the manufacturer's rated throughput capacity by 20 percent. For example, the manufacturer's rated throughput capacity of the Crucial C Disc 13/30 skimmer is 1,181 bph. Consequently, the effective recovery capacity is assumed to be 236 bph. (1,181 bph x 0.20 = 236 bph)	ACS *Technical Manual*, Volume 1, Tactic L-6.
30 CFR 254.26 (d) (2) Deployment and Operation	The quantities and types of field personnel, materials and support vessels to deploy and operate the response oil removal and storage equipment are descr bed in the “Discussion of Equipment, Personnel and Times” section of the scenario.	The locations and owners of the equipment are described in ACS *Technical Manual*, Volume 1, Tactics L-4 and L-6.
30 CFR 254.26 (d) (3) Oil Storage, Transfer and Disposal	The oil storage, transfer and disposal equipment, including barges and oil processing facilities, is descr bed in the scenario.	The types, locations, owner, quantity and capacity of the scenario’s equipment are described in ACS *Technical Manual*, Volume 1, Tactics L-4 and L-6, Section 1.6.3, Temporary Storage and Disposal.
30 CFR 254.26 (d) (4) (i) Time for Procurement of Oil Containment, Recovery and Storage Equipment	Mobilization (i.e., procurement) and transit time is reflected in the scenario.	Mobilization time for equipment is specified in equipment tables in the ACS *Technical Manual* tactics that the scenario incorporates by reference. In addition, BPXA has the capability to mobilize out-of-region resources, if needed. See Tactics L-8, L-9 and L-10.
30 CFR 254.26 (d) (4) (iii) Time for Procurement of Personnel	Mobilization (i.e., procurement) and transit time is reflected in the scenario.	Mobilization time for staff operating vessels and other equipment is specified in the ACS *Technical Manual* tactics equipment tables that list equipment mobilization times. Equipment operators and crews mobilize with their equipment from North Slope origins through ACS contracts and mutual aid agreements; See Tactics L-8, L-9 and L-10 for mutual aid agreements, master agreements and other agreements for accessing equipment.
30 CFR 254.26 (d) (4) (iv) Equipment Loadout Time	The times to transfer equipment to the transportation vessels are reflected in the scenario. The times are included in the mobilization times listed in the ACS *Technical Manual* tactics’ equipment tables that the scenario incorporates by reference.	Equipment loadout time is included in the mobilization times specified for equipment and vessels listed in the ACS *Technical Manual* tactics that the scenario incorporates by reference.
30 CFR 254.26 (d) (4) (v) Travel Time	Times to travel to the deployment site, including from equipment storage are described in the narrative of the scenario.	ACS *Technical Manual*, Tactic L-3 lists travel rates.

TABLE A-1 (CONTINUED): SUMMARY OF HOW THE SCENARIO COMPLIES WITH BSEE REGULATION

BSEE REGULATION	SUMMARY	REFERENCE
30 CFR 254.26 (d) (4) (vi) Deployment Time	Times to deploy equipment are described in the scenario narrative and incorporated by reference to particular ACS *Technical Manual* tactics that list deployment times.	Deployment times are specified in the ACS *Technical Manual* tactics equipment tables that list equipment deployment times.
30 CFR 254.26 (e) (1) Equipment and Strategies are Suitable for Conditions	Response equipment illustrated in the scenario is suitable, within the limits of current technology, for the range of environmental conditions anticipated at the facility. The equipment available on the North Slope and selected for the simulated deployments is the "best available technology" for responding to oil well blowouts in the nearshore Beaufort Sea. Equipment in the scenario have been tested and selected as the most suitable for mechanical oil recovery and in situ burning in the fast ice, broken ice and open water conditions associated with the facility. Response strategies illustrated in the scenario are also suitable, within the limits of current technology, for the range of environmental conditions anticipated at the facility. The strategies of burning and mechanical recovery illustrated in the scenario reflect "best available technology" for the conditions. The strategies have been tested, exercised and selected as most suitable for the conditions.	See the following analyses and reports that indicate the scenario's equipment and strategies are most suitable: 1. Blowout response plans (Section 1.9 of this plan); 2. Results of field tests of vessels, boom, skimmers, and barges in broken ice near Prudhoe Bay (Bronson, 2000a and 2000b). 3. Mechanical recovery and in-situ burning strategy analyses (SL Ross Environmental Research Ltd., DF Dickins Associates, Ltd., and Vaudrey and Associates, 1998). 4. Response strategies and ice considerations in the Endicott area (DF Dickins Associates Ltd., Vaudrey, and Associates, Inc., and SL Ross Environmental Research Ltd., 2000). 5. Access capabilities on rotting ice (Coastal Frontiers Corporation, 2001).
30 CFR 254.26 (e) (2) Standard Terms for Conditions and Equipment Capabilities	The scenario employs standardized, defined terms to define environmental conditions and response equipment. The terms in the scenarios are consistent with terms used in spill response planning in general and for North Slope responses in particular.	For definitions of terms see the following documents: 1. DF Dickins Associates Ltd., Vaudrey and Associates, Inc., and SL Ross Environmental Research Ltd. (2000). 2. Alaska Clean Seas (2010).

OIL SPILL TRAJECTORY [30 CFR 254.26(b)]

The scenario assumes that the oil blows out to the atmosphere from production well MPI 2-52. Oil reaches the surface several hours after a kick is detected. Oil flows at the rate of 1,085 bopd. The gas to oil ratio is 52,743 standard cubic feet per barrel of oil. Over the next 30 days, the blowout discharges a total of 32,550 barrels of crude oil.

The scenario reflects historical ice and weather conditions that are described in Table A-2. The aerial plume of oil follows trajectories that are estimated by predominant wind directions and by the SL Ross plume dispersion model published in ACS *Technical Manual* (2010), Tactic T-6 The wind data were retrieved from the Nearshore Beaufort Sea Meteorological Monitoring and Data Synthesis (Veltkamp and Wilcox, 2007) and a related subsequent project. The predominant wind directions were determined from the 16 cardinal compass directions that blow over 10 percent of the time. The resulting plumes are illustrated in Figure A-1.

In such a blowout, oil impingement on the well house is expected to significantly reduce the size of the oil's aerial plume. Available models do not account for the effect of such impingement on the plume. Consequently, the scenario presents estimates of the oil footprint using the Tactic T-6 model for an un-obstructed plume.

The projected plume dimensions are approximately 5.2 miles long and 3,725 feet wide (at the widest point). See Figure A-1. The model indicates that 10 percent of the discharged oil (3,255 bbl) is in the form of drops so small (50 µm or less) that they do not fall to the ground but are held aloft by atmospheric turbulence. The environment of deposition of the oil that settles to the surface is as follows:

- 56 percent (16,275 bbl) falls to the production pad,
- 41 percent (12,027 bbl) to the Beaufort Sea, and
- 3 percent (993 bbl) to the mainland.

If left unrecovered for 30 days, the average thickness of the discharged oil is 0.4 inches in the Beaufort Sea and 0.001 inches on the mainland.

Once oil is deposited to water it takes the form of windrows and sheen. Movement of oil on the open ocean is affected by two forces – water current and the wind. Oil is predicted to move at the same speed as the underlying water plus approximately 3 percent of the wind speed. The direction and speed of the movement of oil and water can be predicted by vector addition (ACS *Technical Manual*, Tactic T-5).

Ice floe maximum diameters are 500 to 1,000 feet in the first two days of break-up. They diminish to 30 to 40 feet within three weeks. The wind pushes ice of 7 tenths to 9 tenths coverage at 1 to 2 percent of wind speed, concentrations of 4 tenths to 6 tenths coverage at 2 to 3 percent of wind speed, and 3 tenths and less coverage at 3 to 4.5 percent of wind speed. Ice moves 30 degrees to the right of the wind direction.

TABLE A-2: SIMULATED ICE CONDITIONS DURING BREAK-UP

DAY	WIND	SUMMARY	ICE CONDITIONS
May 27	Variable	The Sagavanirktok River overflood reaches the area south of MPI. The north side of the island is not affected by overflood.	Condition 4 (stable ice) develops into Condition 5 (overflood) with the break-up of the ice in the Sagavanirktok River and the overflooding of the bottomfast and floating sea ice just offshore of the Sagavanirktok Delta. The Shaviovik and Kadleroshilik Rivers also flood the landfast sheet ice, but their overflood zones are restricted to a distance of 1 to 2 miles offshore.
June 5	From the NE	Blowout begins. Overflood waters drain through the ice; breakup begins south of MPI. Stable ice north of MPI.	Condition 6 (decaying ice) and Condition 7 (initial break-up) in the Sagavanirktok River overflood zone. Overflood waters drain through the ice leaving a deteriorated but still intact ice surface. Bottomfast ice in the overflood zone has lifted off the bottom in most areas and is melting in situ.
June 10	From the ENE		
June 15	From the ENE	Blowout begins. Final break-up in the vicinity of the Big Skookum bridge. Initial break-up along the south side of the Endicott Causeway, farthest from the river discharge effects. Stable ice north of MPI.	Ice starts to fracture and open south of the Endicott Causeway. Ice conditions here are mostly a mix of open water holes, rotting small floes (in the order of 50 to 100 feet), and/or cakes of ice (tens of feet across by one foot thick) released from the bottom and melting rapidly in the warm, fresh river outflow. Bottom-fast ice persists along the south side of the Endicott Causeway, farthest from the river discharge effects. The landfast ice on the north side of Endicott is intact.
June 23	From the ENE		Mostly open water from the Niakuk Islands to Pt. Brower.
July 1	From the E	Open water on south side of Endicott Causeway. Decaying ice on north side of Endicott.	There is no ice south of the Endicott Causeway (Condition 9). A completely intact ice cover (floating and 3 to 4 feet thick), with many cracks and approximately 40 to 50 percent of its surface covered by meltpools, remains on the north side of Endicott.
July 4	From the E	Initial break-up on north side of Endicott.	Break-up begins with the remaining floating landfast ice on the north side of Endicott.
July 5	From the E	Blowout ends.	
July 12	Variable	Open water on south side of Endicott Causeway. Final break-up on north side of Endicott.	Significant winds disturb the large ice floes north of Endicott. As the winds shift direction, the broken ice floes and pans move back and forth in belts and patches of varying concentrations, all the while melting. First year ice continues to deteriorate and break into smaller floes, creating considerable open water between floes.
July 19	Variable	Open water.	Ice Free – start of open water season. Ice invasion in the area after this date is possible, but unlikely.

Note:

1. The wind data were retrieved from the Nearshore Beaufort Sea Meteorological Monitoring and Data Synthesis (Veltkamp and Wilcox, 2007) and a cooperative monitoring project between BPXA and Shell on Endicott's Endeavor Island.
2. Ice conditions are summarized from Dickins, D.F., K. Vaudrey, and SL Ross (2000).

The floating oil that remains is no longer significantly affected by broken ice from the last week of July until freeze-up in October. Any oil remaining clear of the shore generally moves westward as scattered patches in an open water corridor between the Beaufort Sea coast and the offshore pack ice. Portions of this oil reach scattered sections of shorelines, some as far east as Foggy Island Bay and west to the barrier islands.

Freeze-up begins October 1 in the area south of the Causeway, when the ice is considered shorefast for the season. Freeze-up begins on October 4 north of Endicott. Ice becomes shorefast for the season north of Endicott on October 25. Air temperatures range from 5 to 15°F. Daylight is 9 to 10 hours per day. Ice moves at 4 to 4.5 percent of the wind speed and 30 degrees to the right of the wind direction.

Resources of Importance [30 CFR 254.26(c)]

Resources of special economic or environmental importance could be impacted by the spilled oil. The marine and coastal bird and mammal populations and shoreline cultural resources occupying the path of the spilled oil described in the Trajectory section potentially could be affected by oiling. Many of the birds and mammals are important both ecologically and economically. The ACS *Technical Manual*, Volume 2, lists the marine mammal groups and the marine bird groups that may be potentially exposed to the scenario's oil, and describes their seasonal distribution in the spill vicinity. Threatened and endangered species protection notes are also provided in the *Technical Manual's* map descriptions. In addition, the types of coastal habitats exposed to the oil are listed by level of concern and depicted on maps of the spill area. Catalogued cultural resource sites are listed on the maps that cover their vicinity in the spill area as well. The *Technical Manual* lists are adapted from the Alaska Regional Response Team's "North Slope Subarea Plan."

The first strategy to protect resources of importance is to remove oil quickly and where it still lies in thick layers close to the spill source. Targeting that area can most effectively reduce the quantity of oil available to move into sensitive areas later.

A further strategy is to deploy exclusion and deflection boom at selected shoreline sites. See the priority protection sites marked in the ACS *Technical Manual*, Volume 2, for the area affected by the simulated oil trajectories shown in Figure A-1. ACS *Technical Manual,* Map Atlas maps 67 and 73 show the shorelines near the simulated trajectories. Where pre-staged equipment has been placed on marine shorelines, the maps indicate its location and list the contents of the containers.

To protect shoreline sites from oncoming oil that escapes the offshore oil removal task forces, strike teams of workboats tow delta and harbor boom from West Dock and anchor it in shallow water. Exclusion booming and deflection booming tactics, including equipment lists, personnel numbers, procedures, and mobilization and deployment times, are described in ACS *Technical Manual,* Tactics C-13, C-14 and C-15. The features of the vessels and boom are outlined in Tactic L-6.

To protect birds and mammals, the main strategy is removing oil from the environment. The primary strategy for direct wildlife protection is hazing and collection of oiled carcasses. In the early hours of the spill response, hazing is carried out with ACS equipment and trained personnel under the direction and permits of the Alaska Department of Fish and Game and the U.S. Fish and Wildlife Service. Oiled carcasses are collected to remove them as sources of injury to predators. Oiled animals are captured, stabilized and treated by specialists using ACS equipment, including the wildlife stabilization facility at Prudhoe Bay. Animals requiring further treatment are transported to the Alaska Wildlife Rehabilitation Center in Anchorage. See ACS *Technical Manual* Tactics W-1 to W-6 for decision-making and field procedures.

On the fast sea ice, seal breathing holes are identified and avoided by response operators under advisories from specialists in the Wildlife Unit.

Discussion of Equipment, Personnel and Times [30 CFR 254(d)]

The following discussion illustrates a response to a worst case discharge scenario in adverse weather conditions. The adverse weather conditions involve low temperatures, high winds, periods of fog, short-period waves up to 3 feet and varying ice concentrations. Descriptions of conditions are provided in the Simulated Conditions section of the scenario and in ACS *Technical Manual,* Tactic L-7, Realistic Maximum Response Operating Limitations, for mechanical response equipment. In addition, skimmer capacities are de-rated to reflect the effects of adverse weather among other factors.

The locations, owner and capacities of response equipment, personnel, materials, support vessels, oil storage, transfer, and disposal equipment in the scenario are listed in the ACS *Technical Manual* tactics cited in the narrative. The cited ACS *Technical Manual* tactics are incorporated into the scenario by reference.

Mobilization (procurement) and deployment times of the scenario's containment and recovery, storage equipment, equipment transportation vessels, and personnel to load and operate the equipment are listed in the ACS *Technical Manual* tactics' equipment tables. Equipment loadout times to transfer equipment to vessels are incorporated into the mobilization times. The tables are incorporated into the scenario by reference.

In situ burning and oil recovery operations are conducted on two 12-hour shifts per day. The equipment operates for 10 hours in each 12-hour shift. The remaining 2 hours represent down-time when equipment is out of conformance or conditions are beyond the equipment's operating limitations.

Mobilization of oil containment and removal equipment begins on June 5, Day 1 of the simulated spill. The equipment is deployed at the spill scene. Amphibious and tracked vehicles and airboats mobilized from North Slope sources provide stable work platforms and access to the ice. A staging area is set up at the Duck island Gravel Mine and along the causeway just south of MPI on Days 1 and 2. See Tactics L-2 to L-6 and L-8 to L-10.

Equipment operations and workers on foot follow safety guidelines for vehicle load, ice thickness and ice condition and for walking on deteriorating ice that are found in Sandwell Engineering Inc.'s (2001) *Ice Access Guidelines for Spill Responders*, prepared for ACS. ACS and SRT oil containment and removal crews use site entry protocols detailed in Tactic S-1 (ACS, 2010).

Day 1

On Day 1, the Unified Command determines that ice conditions are not suitable for mechanical oil recovery and transfer equipment. Consequently, the contained oil and oil mixed with ice is burned in situ.

Day 2

Decontamination facilities are set up on the causeway just south of MPI during the initial hours of the response. A mobile decontamination site is mobilized from Prudhoe Bay and set up on Day 2. On Day 2, a safe access work plan is implemented for initial response activities (Tactics S-1 to S-6).

Immediately offshore of MPI, skid steers, tracked Tucker trucks with blades, and Ditch Witches build snow berms (Tactic C-4) and excavate trenches (Tactic C-11 and C-12). See Figure A-2. Partial trenches or through-ice slots are excavated in the ice surface with a Ditch Witch to encourage oil flow to a collection point. The machine cuts slots at the rate of 100 lineal feet per hour. Snow berms and boom are also used to divert oil to the trenches (Tactics C-11 and C-12). West of the pad, crews operate for several days before the ice deteriorates and they demobilize. From June 6 to June 30, oil that spreads to the east of the pad is contained and burned on solid ice and meltpools accessible by surface crews. Residue is collected with hand tools and becomes available (Tactic B-6).

Further offshore on the west side of MPI, oil spill response technicians and equipment operators mobilize their equipment for work on the decaying sea ice and overflood water. The crews mobilize 1,500 feet of fireboom from storage on MPI and deploy it on the ice adjacent to the island to contain oil draining from the island (Tactics C-4 and B-4).

For the first two weeks of the blowout, Unified Command authorizes the use of in-situ burning for this area. Access to this area is achieved by helitorch (Tactic B-3) and airboats (Tactic B-4). As conditions allow, conventional boom and fire boom is deployed in a stationary mode (either anchored to a shore or on the ice) to direct the oil to locations where it can be burned in-situ. If the overflood conditions allow, boom can be towed in a standard U-configuration to collect oil on water and concentrate it for burning within the boom. If conditions do not allow for the deployment of boom, in-situ burning may be conducted by helitorch only (Tactic B-3).

Due to variable and changing ice, overflood, and open-water conditions in the area southwest of the pad and the causeway during break-up, the teams move fire boom locations and modify tactics as necessary.

On Day 5, the wind shifts. Lightly oiled snow on the mainland is accessible. A special tundra travel permit is approved for a team to travel to areas onshore that are affected by discharged oil. As conditions allow, teams use rolligons and snow machines (or equivalent) to access the snow-covered tundra. Trajectory modeling predicts an average thickness on 0.001 inches. Where recovery is feasible, the team uses manual methods (Tactic R-2) to recover oiled snow.

Table A-3 and Table A-4 list the major equipment and staff for oil removal during area-wide break-up.

TABLE A-3: MAJOR EQUIPMENT EQUIVALENTS TO CONTAIN AND REMOVE OIL DURING BREAK-UP

TACTIC	EQUIPMENT	NO. ITEMS
C-4, Berms on Island	Wheeled Backhoe	1
B-4, Burning on Ice near island	Fire Boom, 500 feet	1
C-4 and C-12 B-5 and B-6, Burning on Ice	Tracked Vehicle with Blade, e.g., Tucker Sno-Cat	5
	Airboat to Tend Burning	5
	Airboat for Shuttling	1
	Rolligon with Auger	1
	Fire Boom	1,000 feet
C-11, C-12, Trenching on Ice	Ditch Witch Trencher, e.g. R-100	1
B-3, Ignition on Ice	Helicopter	1
	Helitorch	2
TEAM A TEAM B B-4 [Team A (1), Team B (2)] Burning on Overflood	Airboat to Tend Burning	3
	Fire Boom, Team A	300 lineal feet
	Fire Boom, Team B	600 lineal feet
	Delta Boom, Team A	1,700 lineal feet
	Delta Boom, Team B	5,400 lineal feet
	Airboat for Towing and Shuttling	1
TEAM B (Transitioning to mechanical recovery in open water) R-17 (2), Mechanical Recovery on Lagoon Water	Skiffs for Boom and Skimmer	4
	Delta Boom for Containment	700 feet
	Crucial C Disc 13/30 skimmer	2
	Mini Barge for Shuttling	4
	Shuttle Workboat	2
R-2, Manual recovery of lighted misted snow	Rolligons	1
	Snow machines (with trailers) or Kubotas	3
	Front-end loader (road system only)	1
	Dump Truck (road system only)	1

TABLE A-4: STAFF TO OPERATE OIL CONTAINMENT AND REMOVAL EQUIPMENT

LABOR CATEGORY	TACTIC	NO. STAFF PER TACTICAL UNIT	NO. TACTICAL UNITS	NO. STAFF PER SHIFT
Team Leader	C-4	1	1	1
	B-5, B-6 on ice	1	5	5
	C-11, C-12	1	1	1
	B-3	1	1	1
	B-4(3), B-6(1) in overflood	1	4	4
	R-17	1	1	1
Vessel Operator	B-5, B-6 on ice	1	5	5
<30 ft	B-4(3), B-6(1) in overflood	1	4	4
	R-17	3	1	3
General Laborers	B-5 on ice	1	5	5
	B-3	5	1	5
	B-4(3) on overflood	2	3	6
	R-17	4	1	4
	R-2	6	1	6
General Technician	B-5 on ice	1	5	5
Equipment Operator	C-4	2	1	2
	B-5 on ice	1	5	5
	C-11, C-12	2	1	2
	R-2 (Rolligons, Kubotas, Loaders, Dump trucks)	6	1	6
Total Operators and Technicians[1]	-	-	-	58

[1] Total is sum of vessel operators and technicians; team leaders are vessel operators

Transition to Open Water Season

Beginning Day 15 (June 20), the ice starts to fracture and open large areas south of the Endicott causeway. The overflood burning team's objective shifts from burning tactics (Tactics B-3 and B-4) to mechanical recovery methods (Tactic R-17). See Figure A-4.

Conditions allowing mechanical recovery include when melting ice coverage falls to less than 10 percent. As conditions allow, two pair of shallow draft workboats tow delta containment boom in a J configuration and support a Crucial C Disc 13/30 skimmer in the boom apex. Shuttle boats transport recovered oil and water to vacuum trucks stationed at a fluid transfer area set up on the causeway. The team's capacity to recover oil is detailed in Table A-5. Table A-6 and Table A-7 detail major equipment and staff required for oil removal after area-wide break-up.

The recovered oil is stored in mini-barges. The mini-barges hold 100 barrels, less than their 249-barrel capacity, to reduce draft and prevent grounding. Two mini-barges handle the loading, interim storage, and shuttling of recovered liquids. The recovery team loads a mini-barge, then the loaded mini-barge is shuttled with a workboat, offloaded, and returned to the recovery team. The mini-barges, towed by workboats, offload at the fluid transfer area on Endicott causeway to vacuum trucks. Ullage tape gauges the oil and water cut volumes in the mini-barges at the causeway staging area.

Burn residue can normally be picked up with large strainers or handtools, with viscous-oil sorbents, or with standard viscous-oil skimmers (Tactic B-6), whether recovered from secondary booms or the fire containment boom.

Burn residue and other non-liquid oily wastes are hauled in covered tote containers to the staging area by airboats for interim storage. Volumes are measured in the containers and logged on manifests. Residue is transferred by a freighter airboat with shuttling capacity exceeding the rate that residue becomes available. The freighter airboat travels an average of 10 mph on ice and water on 1-mile round trips.

As the ice recedes, shoreline protection strike teams in workboats tow delta and harbor boom from West Dock and anchor it in shallow water. Exclusion booming and deflection booming tactics, including equipment lists, personnel numbers, procedures, and mobilization and deployment times, are described in ACS *Technical Manual,* Tactics C-13, C-14 and C-15. The features of the vessels and boom are outlined in Tactic L-6. The teams deploy boom at priority protection sites first.

Mainland onshore areas downwind of the blowout are monitored by assessment teams to determine the distribution of oil on tundra and shorelines (Tactics SH-1, T-1, and T-2). The teams search for oiled areas from a helicopter and from two Rolligons operating under an emergency tundra travel permit. The teams employ assessment protocols specific to Alaska and arctic environments (NOAA, 1994; NOAA 2000; USCG, 2010).

On June 30, the Unified Command halts on-ice operations in the area to the east of MPI in anticipation of break-up. Ice tracking beacons and buoys are deployed with the objective of tracking potentially remaining oil as the ice breaks up (Tactic T-4A). A helicopter with a helitorch is dispatched daily to burn oil patches on ice and water (Tactic B-3) July 1 to 4. On July 4, break-up begins in the area east of the pad.

On July 1, there is no ice south of the causeway, and on-water recovery continues. Shallow draft workboats tow delta containment boom in a J configuration (Tactic R-17) and U boom with open apex (Tactic R-20). The workboats use Crucial C Disc 13/30 skimmers for on-water recovery. Shuttle boats transport recovered oil and water to vacuum trucks stationed at a fluid transfer area set up on the causeway.

In-situ burning continues east of the pad as the broken ice coverage decreases (Tactic B-3). A helitorch ignites isolated pockets of oil on the water and oil on ice pieces. Two workboats collect burn residue with hand tools (B-6) and offload to lined dump trucks at the staging area on the causeway. The residue quantity is estimated by volume measurements at the causeway fluid transfer area.

By July 12, the entire area around MPI is ice free. Ice invasion in the area after this date is possible, but unlikely. Recovery operations and daily aerial surveillance continues until fast ice forms in October.

During the initial recovery operations, a Liquid Transfer Task Force assembles at the staging area on the causeway. Once there is vessel access to MPI, the Liquid Transfer Task Force is moved to MPI. The stored liquids are offloaded from the mini-barges to vacuum trucks (Tactic R-22). The volumes of stored oil and free water are gauged with ullage tape in the barge tanks.

The Environmental Unit includes a three-person Waste Management Team to (1) fill out and sign manifests, (2) measure liquid and other waste and (3) submit a plan to Unified Command for waste management. Burn residue and non-liquid oily wastes are transported and handled for ultimate disposal appropriately, as recommended in the *Alaska Waste Disposal and Reuse Guide*. Liquid and non-liquid oily wastes are processed as described in Tactics D-1 and D-2.

A special tundra travel permit is approved for a team to travel to impacted areas on the mainland coast. As conditions allow, teams use rolligons to access tundra and ponds. Trajectory modeling predicts an average thickness of 0.001 inches. The team uses portable skimmers and fast tanks (Tactic R-8) to recover pockets of oil from ponds and lakes.

Shoreline cleanup teams recover oil on marine shorelines using methods recommended by the Shoreline Cleanup Assessment Teams, reflected in a shoreline cleanup plan, and approved by the Unified Command (Tactics SH-1 to SH-12).

Table A-5 and Table A-6 list equipment and staff that remove oil after the blowout ends. Table A-7 lists skimmer capacities.

TABLE A-5: MAJOR EQUIPMENT TO REMOVE OIL AFTER THE BLOWOUT ENDS

EQUIPMENT	NO. TACTICAL UNITS	NO. ITEMS
Helicopter with helitorch	1 ea. B-3	1
Workboat, Type C	2 ea. B-6	2
Skiffs for boom towing and skimmer		8
Boom		1,400 lineal feet
Crucial C Disc 13/30 skimmer	1 ea. R-17	4
Mini barge		8
Workboat for shuttle		4

TABLE A-6: SKIMMER CAPACITIES

A	B	C	D	E
SKIMMER & ICE CONDITION	**NO.**	**DE-RATED OIL RECOVERY RATE (boph)**	**DAILY EFFECTIVE OIL RECOVERY RATE (bopd) C X 20 HOURS**	**SUM OF DAILY EFFECTIVE OIL RECOVERY RATES (bopd) B X D**
During Blowout				
Crucial C Disc 13/30 skimmer , R-17, ice <1/10[1]	2	236	4,720	9,440
After Blowout				
Crucial C Disc 13/30 skimmer , R-17, open water[2]	4	236	4,720	18,880

[1] Two R-17 teams work in the Sagavanirktok River Delta during the blowout.

[2] Four R-17 teams work after the blowout.

TABLE A-7: STAFF TO OPERATE OIL REMOVAL EQUIPMENT AFTER THE BLOWOUT ENDS

LABOR CATEGORY	TACTIC	NO. STAFF PER TACTICAL UNIT	NO. TACTICAL UNITS	NO. STAFF PER SHIFT
Team Leader	B-3 (1) B-6 (2), R-17 (1)	1	4	4
	R-2	1	1	1
Small Vessel Operator, <30 ft	R-17	3	3	12
	B-6	1	2	2
Skilled Technicians	R-17	4	4	16
	B-3	5	1	5
	B-6	2	2	4
General Laborers	R-2	6	1	6
Equipment Operator	R-2 (Rolligons, Kubotas, Loaders, Dump trucks)	6	1	6
Total Operators and Technicians[1]	-	-	-	56

[1] Total is sum of vessel operators and technicians; team leaders are vessel operators.

In the ice-free season, July 19 to September 30, mechanical oil recovery efforts continue. The detached J containment and skimming (R-17) teams that operated in the broken ice earlier in July continue their efforts daily on day and night shifts in the ice-free conditions from July to October. Their objective is to remove oil on the water that may remain after the earlier removal efforts.

As the nearshore Beaufort Sea freezes after September 30, oil removal operations are reduced and then suspended for the winter. The on-water teams continue to target oil for removal in the ice-free water areas. However, the teams avoid taking paths through areas where grease, slush and new ice are forming. See Tactic L-7.

During the freeze up period, aerial monitoring continues. Patches of scattered oil are reported and mapped until the area supports fast ice.

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ASE File 209.03

United States Department of the Interior

MINERALS MANAGEMENT SERVICE
Alaska Outer Continental Shelf Region
3801 Centerpoint Drive, Suite 500
Anchorage, Alaska 99503-5823

JUL 17 2007

Mike Bronson
BP Exploration (Alaska) Inc.
P.O. Box 196612
Anchorage, Alaska 99519-6612

Dear Dr. Bronson,

This is in response to your letter dated July 2, 2007 requesting the Minerals Management Service review and approval of the BP Exploration (Alaska) Inc. (BPXA) Endicott-Badami Oil Discharge Prevention and Contingency Plan (ODPCP) dated May 2007. The ODPCP was prepared in accordance with the State of Alaska Oil and Hazardous Substances Pollution Control Regulations and submitted to satisfy the MMS regulations 30 CFR 254.53 for compliance with the Federal Oil Pollution Act of 1990. The MMS' review of the plan is limited to the Endicott facilities that directly pertain to offshore oil and gas exploration and production activities and offshore pipeline transportation of produced oil, including distillates or condensate associated with produced natural gas. This plan was submitted to meet ODPCP renewal requirements for both Alaska Department of Environmental Conservation (ADEC) and the MMS.

The MMS has completed its review of the document and determined that the ODPCP adequately addresses MMS oil spill response requirements for offshore activities. Therefore the Endicott-Badami ODPCP is hereby approved. Review and renewal of this plan will be based on the State of Alaska's 5-year schedule with renewal required on or before May 22, 2012.

Since BPXA is submitting a State of Alaska ODPCP to satisfy MMS requirements, BPXA will provide notifications of non-readiness and proposed modifications and amendments to the ODPCP, as required in18 AAC 75, to the MMS at the same time they are presented to the State of Alaska.

If you have any questions, please contact me at (907) 334-5309 or by email at christy.bohl@mms.gov.

Sincerely,

Christy A. Bohl
Oil Spill Program Administrator

cc: Graham Wood, ADEC

BP EXPLORATION (ALASKA) INC.

OIL DISCHARGE PREVENTION AND CONTINGENCY PLAN

ENDICOTT OPERATIONS AND BADAMI PIPELINE
NORTH SLOPE, ALASKA

VOLUME 2 OF 2, PREVENTION PLAN

APRIL 2012

BP EXPLORATION (ALASKA) INC.

ENDICOTT OPERATIONS AND BADAMI PIPELINE OIL DISCHARGE PREVENTION AND CONTINGENCY PLAN

Volume 2 of 2, Prevention Plan

APRIL 2012

RECORD OF REVISIONS – VOLUME 2

REVISION NUMBER	REVISION DATE	SUMMARY OF REVISION CHANGE
1	August 2012	**Part 2:** Language in Section 2.5.6, Crude Oil Transmission Pipelines Discharge Detection, was updated describing the circumstances for increased alarm thresholds on the Badami Crude Oil Transmission Pipeline (COTP). **Part 3:** In Table 3-1, Regulated Stationary Oil Storage Tanks greater than 10,000 gallons, CIC Tank Integrity 2011 inspection dates were updated for tanks T-E3-1102 and T-E3-1802. **Appendix A:** The following changes were made to the Portable Shop-Fabricated Tank Table: • CIC Tank Integrity 2011 Inspection updates were updated; • Removed from service/surplussed tanks 73011 (GPB, 73031 (GPB), END-02 (END SDI) were deleted; and • DOT-regulated Tank 90-869 was removed because it is not regulated by ADEC.
2	March 2013	**Part 2:** • The March 4, 2005 ADEC waiver from daily secondary containment area inspection requirements during Phase 2 and Phase 3 weather conditions was replaced with the revised ADEC waiver dated November 3, 2011. • The December 17, 1996 ADEC waiver from secondary containment requirements for Waste Water Tank T-E3-1802 was replaced with a new ADEC waiver dated March 1, 2013. **Part 3:** In Table 3-1, Regulated Stationary Oil Storage Tanks greater than 10,000 gallons, CIC Tank Integrity inspection dates were updated for tanks inspected in 2012 and the module number associated with dirty water tank T-E3-1802 was corrected.
3	April 2013	**Appendix A:** The following changes were made to the Portable Shop-Fabricated Tank Table: • CIC Tank Integrity Inspection updates were updated; • Tank T-100420 was removed; and • Tanks T-20451 and T-20452 were tagged as not in service.

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LIST OF ACRONYMS – VOLUME 2

°F	degrees Fahrenheit
AAC	Alaska Administrative Code
ACS	Alaska Clean Seas
ADEC	Alaska Department of Environmental Conservation
AOGCC	Alaska Oil and Gas Conservation Commission
API	American Petroleum Institute
ASME	American Society of Mechanical Engineers
BAT	best available technology
bopd	barrels of oil per day
boph	barrels of oil per hour
BPTA	BP Transportation (Alaska) Inc.
BPXA	BP Exploration (Alaska) Inc.
CFR	Code of Federal Regulation
CIC	Corrosion, Inspection and Chemicals
CP	cathodic protection
CPER	chlorinated polyethylene
CRM	corrosion rate monitoring
CUI	corrosion under insulation
DOT	U.S. Department of Transportation
EAP	Employee Assistance Program
EFA	Ed Farmer and Associates
ESD	emergency shutdown
FLIR	Forward Looking Infrared
GAnB	general anaerobic bacteria
HCP	Hearing Conservation Program
HLA	high liquid level alarm
HSSEE	Health, Safety, Security, Environment and Engineering
IPP	Industry Preparedness Program
MBLPC	mass balance line pack compensation
MIC	microbiologically influenced corrosion
mmscf	million standard cubic feet
MPI	Main Production Island
N/A	not applicable
NACE	National Association of Corrosion Engineers
NDT	nondestructive testing
NSTC	North Slope Training Cooperative
ODPCP	Oil Discharge Prevention and Contingency Plan
OSHA	Occupational Safety and Health Administration
PHMSA	Pipeline and Hazardous Materials Safety Administration

PLC	Programmable Logic Controller
PPA	Pressure Point Analysis
psi	pounds per square inch
ROM	rough order of magnitude
RPP	Respiratory Protection Program
RTU	Remote Terminal Unit
SDI	Satellite Drilling Island
SDV	shutdown valve
SPAR	Division of Spill Prevention and Response
SSSV	subsurface safety valve
SSV	surface safety valve
STI	Steel Tank Institute
TAPS	Trans Alaska Pipeline System
V	velocity
Ve	calculated erosion velocity limit
VSM	vertical support member
WW	Well Work

INTRODUCTION

Volume 2 of this Oil Discharge Prevention and Contingency Plan (ODPCP) addresses oil spill prevention requirements promulgated by the State of Alaska in Title 18, Chapter 75 of the Alaska Administrative Code (AAC). As allowed under 18 AAC 75.425(e)(2), the ODPCP is represented by two volumes: Volume 1, Response Action Plan, and Volume 2, Prevention Plan. The Prevention Plan, Volume 2 of 2, is contained herein.

PLAN DISTRIBUTION

The Prevention Plan is maintained on the BP Exploration (Alaska) Inc. (BPXA) intranet website, accessible by BPXA employees and contractors. Copies of the plan are distributed to regulatory agencies. Additional copies are in the Anchorage Crisis Center, the Health, Safety, Security, Environment, and Engineering (HSSEE) Department, and at Alaska Clean Seas (ACS). A record of plan distribution is maintained by the HSSEE Department.

UPDATING PROCEDURES

The Prevention Plan is reviewed annually and revised and updated when changes occur. Below is a list of key factors that may cause revisions to the plan:

- New developments,
- New pipeline construction or purchase,
- Change in commodities transported,
- Change in prevention procedures, or
- Change in ownership.

PLAN RENEWAL

The plan is renewed every five years, based on the State of Alaska's renewal cycle.

ACKNOWLEDGMENTS

Gratitude is extended to the many contributors who helped revise Volume 2 of the ODPCP. The following BPXA personnel oversaw revisions:

Bronson, Mike	Entire volume
Smith, Angi	Sections 2.1.2, 2.1.3
Armstrong, Randy Kuzma, John Johnson, Elden Sieh, Chris Stelley, Travis Susich, Mark Tabinor, Matt	Sections 2.1.7, 2.1.11, 2.1.12, 4.8, 4.9
Cocklan-Vendl, Mary Dowling, Peter Pomeroy, Glen	Sections 2.1.7, 2.1.8, 2.1.11
Bruchie, Dave	Sections 2.1.8, 2.5.6, 3.1.4, 4.10
Domingue, Shane Gross, Terry Walters, Jeff	Section 2.1.9, Table 3-1, Appendix A
Morales, Josh	Sections 2.1.10
Bill, Michael	Sections 2.5.1 and 2.5.2
Kany, Geoff Paul, Kristin	Sections 2.1.10, 2.5.7, 3.1.4
Glover, Nick	Section 2.3
Dunn, Joe McLeod, Shane	Section 4.7

Additional contributors were as follows:

Carr, Aaron. AeroMetric Cartographer	Appendix B, Facility Diagrams
Kendall, Mer, Oasis Environmental	Appendix C, Discharge History
Miner, Lydia, SLR International Corp	Entire volume

STATE OF ALASKA

DEPT. OF ENVIRONMENTAL CONSERVATION
DIVISION OF SPILL PREVENTION AND RESPONSE
INDUSTRY PREPAREDNESS PROGRAM

SEAN PARNELL, GOVERNOR

555 Cordova Street
Anchorage, AK 99501
PHONE: (907) 269-3094
FAX: (907) 269-7687
http://www.dec.state.ak.us/

March 27, 2012

File No: 305.30
(BPXA End-Bad)

Mike Bronson
Eppie Hogan
BP Exploration (Alaska) Inc.
P.O. Box 196612
Anchorage, AK 99519-6612

Subject: **BP Exploration (Alaska) Inc. Oil Discharge Prevention and Contingency Plan for Endicott Operations and Badami Pipeline, North Slope, Alaska. Plan Number 11-CP-4130. Plan Approval**

Dear Mr. Bronson and Ms. Hogan:

The Alaska Department of Environmental Conservation (department) has completed our review of your application for the above referenced Oil Discharge Prevention and Contingency Plan (plan) dated December 2011. The department coordinated the State of Alaska's public review for compliance with 18 AAC 75, using the review procedures outlined in 18 AAC 75.455. Based on our review, the department has determined that your plan is consistent with the applicable requirements of the referenced regulations and is hereby approved.

This approval applies to the following plan:

Plan Title:	**BP Exploration (Alaska) Inc. Oil Discharge Prevention and Contingency Plan for Endicott Operations and Badami Pipeline, North Slope, Alaska**
Supporting Documents:	**Alaska Clean Seas (ACS) Technical Manual, © June 2010, as revised and updated**
Plan Holder:	**BPXA Exploration (Alaska) Inc. 900 East Benson Boulevard P. O. Box 196612 Anchorage, AK 99519-6612**

Covered Facilities: **Production and drilling operations conducted within the Endicott Operations Area, operation of the Endicott crude oil transmission pipeline from the Main Production Island to the Eastern Operations Center, and also the Badami crude oil transmission pipeline from the Badami Development Area to the Endicott pipeline**

PLAN APPROVAL: Approval of the referenced plan is hereby granted, effective **March 27, 2012**. 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).

1. **Notice of Changed Relationship with Response Action Contractor**. Because the plan relies on the use of response contractors for its implementation, BP Exploration (Alaska) Inc. (BPXA) must immediately notify us in writing of any change in the contractual relationship with the plan holder's response action contractors, 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. **Management Approval and Manpower Authorization Form**. A signed copy of the Management Approval and Manpower Authorization form must be provided in the final plan distribution or submitted to the department in accordance with 18 AAC 75.425(e)(c)(3).

   This condition is reasonable and necessary to ensure that a statement signed by a person with appropriate authority to commit the oil discharge prevention and response resources necessary to implement the plan is submitted as required by 18 AAC 75.425(e)(c)(3).

2. **Blowout Contingency Plan.** A copy of the Blowout Contingency Plan (BCP) must be maintained at the Endicott facility and made available to the department upon request.

   This condition is necessary to ensure that the plan holder is prepared to control a potential well blowout. The department will review the blowout contingency plan when performing site inspections and/or in Anchorage BPXA offices. 18 AAC 75.425(e)(1)(I), 18 AAC.445(d)(2), and 18 AAC 75.480.

3. **Revision to Table 2-9: Visual Surveillance Requirements.** Table 2-9 is lacking visual surveillance information for the Badami crude oil transmission pipeline. BPXA must include an entry reflecting that aerial surveillance is performed on the Badami crude oil transmission pipeline weekly unless precluded by safety or weather, in accordance with 18 AAC 75.055(a)(3). This information will be shown in revisions for the first amendment to the approved plan.

   This condition is necessary to ensure that the plan is consistent with regulatory requirements and accurately describes the visual surveillance activity performed for this pipeline. 18 AAC 75.425(e)(2)(E) and 18 AAC 75.055(a).

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. BPXA must send three complete plan copies to the Exploration, Production & Refineries Section. 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 27, 2017**. 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 Jeanne Swartz at (907) 269-7604 or at jeanne.swartz@alaska.gov.

Sincerely,

Betty Schorr

Betty Schorr
Program Manager

Attachment: Summary of Basis for Department Decision

Enclosure: Certificate of Approval, Number 12CER-011

Electronic cc: (w/o enclosure)

Scott Pexton, ADEC
Tom DeRuyter, ADEC
John Ebel, ADEC
Gordon Brower, NSB
Roy Varner, Sr., NSB
Hon. Charlotte Brower, NSB
Jake Adams, NSB
John Boyle, III, NSB
Richard Camilleri, NSB
C-Plan Reviewer, ADNR
Tony Cabinboy, NSB
Christy Bohl, BSEE
Mike Thompson, JPO
Jack Winters/Todd Nichols, ADFG
Matt Carr, USEPA
Melanie Barber, USDOT
MSTC Shawn Erwin, USCG
MST1 Brian Schughart, USCG
LCDR Bradley Clare, USCG
Pam Miller, Northern Alaska Environmental Center

Susan Harvey, Harvey Consulting
Legal Director, Trustees for Alaska
Tony Parkin, BPXA
Lydia Miner, SLR

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

Certificate Number: **12CER-011**

Plan Number: **11-CP-4130**

Name of Plan: **BP (Exploration) Alaska, Inc. Endicott Operations and Badami Pipeline North Slope Production Oil Discharge Prevention and Contingency Plan**

Covered Facilities: **Production and drilling operations conducted within the Endicott Operations area and operation of the Badami crude oil transmission pipeline from the Badami Development Area to the Endicott Pipeline**

Address: **BP (Exploration) Alaska, Inc., 900 East Benson Boulevard, Anchorage, AK 99508 or P. O. Box 196612, Anchorage, AK 99519**

Telephone: **(907) 564-5111** Fax: **(907) 564-5020**

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

Effective Date of Approval: **March 27, 2012** Expiration Date: **March 27, 2017**

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 03.27.2012

Betty Schorr, Approving Authority **Date**

Program Manager, Industry Preparedness Program

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

Part 1, Response Action Plan, is in Volume 1.

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

This part describes how Endicott and the Badami pipeline meet the applicable parts of 18 AAC 75, Article 1. The descriptions in this part reflect a number of BPXA's internal guidance documents not incorporated into this plan.

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

BP Exploration (Alaska) Inc. (BPXA) is responsible for all oil spill prevention regulatory compliance at Endicott and for the Badami pipeline.

The facility's oil spill prevention programs consist of the equipment and activities required by applicable parts of the Alaska Department of Environmental Conservation (ADEC) oil spill prevention regulations (18 AAC 75 Article 1).

2.1.1 OIL DISCHARGE PREVENTION TRAINING PROGRAMS [18 AAC 75.020(a) THROUGH (c)]

BPXA employees with job duties directly involving inspection, maintenance or operation of oil storage and transfer equipment on BPXA leases are trained by way of BPXA's Oil Discharge Prevention Regulation Training course or discipline-specific modules. Those courses provide instruction in the ADEC oil spill regulations' requirements applicable to BPXA "oil handling" personnel and regulated equipment on the North Slope. Topics comprise the following: spill prevention regulations training requirements, drug and alcohol abuse prevention programs, inspections recordkeeping, truck-to-tank transfers, well cellars, tank design and inspections, secondary containments design and inspection, crude oil transmission pipeline leak detection, and inspections of flow lines and facility oil piping. The training program involves lists of BPXA personnel by name and job who inspect, maintain, and operate regulated oil tanks and truck-to-tank transfer equipment, and their training histories. (The terms "oil storage" and "transfer equipment" mean tanks and secondary containment areas described in Part 3 of this plan, plus the facility piping and truck fluid transfer equipment on BPXA leases and as described in 18 AAC 75, Article 1.)

BPXA also requires contractor "oil handlers" to have training required by the regulations. Contractors may train by way of BPXA's program or by way of their own programs. Contractors record the completions of their spill prevention training that complies with the regulations. They make tallies of the completions available to BPXA primarily by way of ISNetworld's internet service. In turn, BPXA spot-checks the contractors' reports to determine whether contractor companies are training oil-handling staff regarding spill prevention.

Oil handlers also receive training on the operation and maintenance of oil equipment, oil spill protocols, and general facility operations. Oil spill prevention training and oil spill prevention briefings for oil-handling personnel are held annually. In addition, unescorted workers on BPXA leases receive spill prevention training through the North Slope Training Cooperative (NSTC) program.

BPXA maintains records of its employees' oil spill prevention training required by 18 AAC 75 Article 1. Records are kept for at least five years. They are provided to the ADEC upon request. Contractors maintain their own training records.

BPXA employees and contractor personnel working on the North Slope receive copies of the *North Slope Environmental Field Handbook*. It provides an overview of state and federal spill prevention regulations and programs applicable to the North Slope oil fields and summarizes procedures to comply with those regulations. In particular, the handbook explains fluid transfer procedures, drip liner usage, secondary containment, and spill reporting.

Facility and response personnel are provided a mandatory site orientation that includes familiarization with facility Emergency Response Plans.

Facility personnel also receive training on the BPXA Environmental Management System. The training outlines how to report oil spills. BPXA's Environmental Management System promotes continual improvement in environmental performance. The system uses direct input from technical specialists and field personnel, and information developed through routine loss control and incident investigations, to minimize the potential recurrence of events.

Environmental communications and bulletins are regularly distributed to ensure specific safety and environmental issues are communicated. Most supervisors discuss environmental communications and bulletins with their crews during daily and weekly toolbox safety meetings.

2.1.2 SUBSTANCE ABUSE PROGRAMS [18 AAC 75.007(e)]

The BPXA drug and alcohol policy promotes the safety of employees, contractors, and non-employees, and provides a safe working environment. BPXA employees are prohibited from being under the influence of illicit drugs, alcohol, or the misuse of prescription medications, when conducting company business. Individuals are prohibited from the following upon entering company-owned, leased or operations facilities:

- Possession of illicit drugs or alcohol,
- Possession of controlled substances without a physician assistant's knowledge,
- Under the influence of any illicit drug, alcohol, the misuse of prescription medications, and
- Distribution or sale of drugs or alcohol.

BPXA complies with the U.S. Department of Transportation (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) drug and alcohol testing regulations set forth in 49 Code of Federal Regulations (CFR) Part 199, and the DOT Procedures for Transportation Workplace Drug & Alcohol Testing Programs in 49 CFR Part 40. BPXA employees involved in safety-sensitive positions within natural gas, liquefied natural gas, and hazardous liquid pipeline operations under the umbrella of operations, maintenance or emergency response definitions are subject to tests. These tests are for pre-employment, reasonable cause, post-accident (per the definition stated in the respective drug testing procedure), return to duty, follow-up drug testing (post-rehabilitation), and tests on a random basis in accordance with the DOT PHMSA regulation. Other BPXA employees fall under the company's non-DOT drug testing program. Each group is randomly tested at a rate of a minimum of 25 percent per year. Contract personnel maintain their own drug testing program records. The testing must meet the minimum standards set by BPXA.

Being under the influence of illicit drugs or the misuse of prescription drugs by an employee, while performing BPXA business or while in a company facility, is prohibited.

Being under the influence of alcohol by an employee, while performing company business or while in a company facility, is prohibited.

Implementation of the BPXA Substance Abuse Program is divided into three parts as follows:

- Training is available to both employees and supervisors to teach them to detect signs of abuse in themselves and the people with whom they work. Information is provided on the available rehabilitation programs.
- The company has jurisdiction to perform a drug or alcohol test on employees when there is legitimate cause, such as medical surveillance following rehabilitation, or as post accident or reasonable suspicion drug and/or alcohol screening. The company makes every effort to support its employees and strongly encourages medical rehabilitation (i.e., self identification of a substance abuse problem).
- Upon the discovery of illicit drug use, controlled substance abuse, or alcoholic beverage possession, an employee will be subject to disciplinary action up to and including termination.

In addition, BPXA has a DOT Alcohol Misuse Prevention Program that involves testing for the following: post-accident, reasonable cause, return-to-duty, and follow up.

The BPXA Work Life and Employee Assistance Program (EAP) is an elemental part of rehabilitation. EAP is a confidential counseling and referral service. BPXA also supports medical rehabilitation programs outside of the Employee Assistance Program, which are covered by the BPXA medical plan.

2.1.3 MEDICAL MONITORING [18 AAC 75.007(e)]

New BPXA employees receive an entrance physical examination to establish baseline health conditions. Under federal and state Occupational Safety and Health Administration (OSHA) requirements and Alaska Department of Occupational Safety and Health requirements, medical monitoring is conducted as required by the type of work performed. Emergency response personnel have annual medical examinations, which include a physical exam, audiogram, respiratory exam, electrocardiogram, x-rays (when applicable), and blood work. All other BPXA employees who are field workers receive annual respiratory exams and audiograms if required to be in the company's Hearing Conservation Program (HCP) and/or the Respiratory Protection Program (RPP) by the Industrial Hygiene Team.

(b) (7)(F)

[redacted]

(b) (7)(F) [redacted]

2.1.5 FUEL TRANSFER PROCEDURES [18 AAC 75.025]

Measures are taken to prevent spills or overfilling during a transfer of oil. Loading rates are reduced at the beginning and end of a transfer, as required by 18 AAC 75.025(a). "Transfer" means oil movement between a tank and tank truck, tank vessel, or tank barge.

Each person involved in a regulated transfer of oily fluids is capable of clearly communicating orders to stop a transfer during the transfer, as required by 18 AAC 75.025(d).

A positive means is provided to stop a transfer of oily fluid, as required by 18 AAC 75.025(e).

Before beginning a transfer at an area not protected by secondary containment, the valves in the transfer system are checked to make sure they are in the correct position. Manifolds not in use are blank flanged or capped. Transfer piping and hoses used in the transfer are checked for damage or defects before the transfer and during the transfer.

The lowermost drain and the outlets of a truck oily fluid cargo tank are examined for leaks before the truck's tank is filled and again before the truck departs, as required by 18 AAC 75.025(g). The truck's manifold is blank flanged or capped and valves are secured before it leaves the transfer area. Surface liners at inlet and outlet points are the primary prevention mechanisms against discharge to the ground during the transfer of liquids.

Effective communication and planning are key factors in preventing spills. Trucks are continuously staffed during fluid transfers and transfer personnel have radios. Manual shutoff valves are available to the truck operator to stop transfers.

2.1.6 OPERATING REQUIREMENTS FOR EXPLORATION AND PRODUCTION FACILITIES [18 AAC 75.045]

Produced oil from flow tests and other drilling operations is handled in a manner to prevent spills [18 AAC 75.045(a)]. Oil produced from flow tests may be flowed directly to the plant or stored in mobile tanks.

The requirements for platform integrity inspections and isolation valves for pipelines leaving platforms do not apply [18 AAC 75.045(b) and (c)].

Impermeable well cellars at Endicott fulfill the requirements for drip pans or curbing at offshore facilities and well head sumps for onshore facilities [18 AAC 75.045(d)].

Catch tank requirements do not apply [18 AAC 75.045(e)].

Information pertaining to flow lines, oil storage tanks, and facility oil piping is found later in this Part and in Part 3 [18 AAC 75.045(f) through (g)].

2.1.7 REQUIREMENTS FOR FLOW LINES AT PRODUCTION FACILITIES [18 AAC 75.047]

Table 2-1 summarizes methods for meeting the requirements of 18 AAC 75.047.

TABLE 2-1: FLOW LINE COMPLIANCE

CITATION 18 AAC 75.047	REGULATORY STANDARD	ADEC-REQUIRED ENGINEERING STANDARD	HOW THE STANDARD IS MET
(b)	The design and construction of each flow line placed in service after December 30, 2008 is consistent with … [American Society of Mechanical Engineers] ASME B31.4-2002 … or B31.8-2003.	ASME B31.4 – 2002 ASME B31.8 – 2003	BPXA Pipelines internal guidance stipulates design procedures consistent with the standard.
(c)(1)	Measures for controlling corrosion in flow lines are …a corrosion monitoring and control program consistent with Chapter VIII of … ASME B31.4-2002	ASME B31.4 – 2002	BPXA Corrosion, Inspection and Chemicals (CIC) internal guidance stipulates a corrosion monitoring and control consistent with the standard.
(c)(2)	External corrosion control of buried …flow lines consistent with … [National Association of Corrosion Engineers] NACE, RP0169-2002.	NACE RP0169 – 2002	Not applicable; buried flow lines are not present.
(c)(3)	External corrosion control of aboveground flow lines by … protective coating, … corrosion resistant alloys, … or another method; … or the anticipated extent of corrosion will not affect the flow line's fitness for service.	None	The anticipated extent of external corrosion of aboveground flow lines will not affect fitness for service. Aboveground flow lines installed after 2006 are protected from atmospheric corrosion by fusion bonded epoxy and/or are made of corrosion resistant alloy.
(c)(4)	Flow lines are in a program designed to minimize internal corrosion, including maintenance pigging and chemicals.	None	Internal facility-specific corrosion control plans stipulate internal corrosion control techniques.
(d)(2)(B)	Preventative maintenance program … for buried flow lines is consistent with Chapters VII and VIII of … ASME B31.4-2002.	ASME B31.4 – 2002, Ch. VII and VIII	Not applicable; buried flow lines are not present.
(d)(2)(C)	For aboveground flow lines, as appropriate, a preventative maintenance program consistent with…API 570 and … Chapters VII and VIII of … ASME B31.4-2002	API 570* ASME B 31.4 – 2002, Ch. VII and VIII	BPXA internal guidance stipulates preventative maintenance procedures consistent with the standards.
(d)(2)(D)	For all flow lines, procedures to review proposed changes in operations to evaluate potential impacts on pipe integrity.	None	BPXA's internal management of change procedures address operational changes and effects on flow lines.
(e)	Line markers shall be installed … and maintained over each onshore flow line at each road crossing and at one-mile intervals along the remainder of the pipe to identify and, for buried pipe, properly locate each flow line.	None	Under a waiver received from ADEC on September 12, 2007, BPXA has flow line markers at road crossings in lieu of one-mile intervals.

TABLE 2-1 (CONTINUED): FLOW LINE COMPLIANCE

CITATION 18 AAC 75.047	REGULATORY STANDARD	ADEC-REQUIRED ENGINEERING STANDARD	HOW THE STANDARD IS MET
(f)	Flow lines removed from service for more than one year and not maintained in accordance with [18 AAC 75.047] (c) and (d) …must be free of accumulated oil and isolated from the system….Notify the department when flow lines are removed from service [and when they are free of accumulated oil]….A flow line removed from service is free of accumulated oil if in the case of a piggable pipe, a cleaning pig is run through the pipe; [or] in the case of a pipe that is not piggable but that can be drained entirely of its contents by gravity, the pipe is completely drained of oil; or in all other cases, air is blown through the pipe or another method is used to flush or evacuate standing oil accumulated in low spots. "Removed from service" means the flow line is not in regular use for its intended service (i.e., hydrocarbon service) and no longer in a regular maintenance and inspection program required by ADEC.	None	BPXA Pipeline group internal guidance stipulates how to remove oil and isolate the system. Flow lines no longer maintained under an ADEC-required corrosion monitoring and preventive maintenance program are, within one year, made free of accumulated oil and isolated from the system. The pipe is treated with a cleaning pig, completely drained of oil, or blown with air or with another method to evacuate standing oil. The out-of-service notices to ADEC's Division of Spill Prevention and Response (SPAR), Industry Preparedness Program (IPP), are made by BPXA's Pipelines group by way of reports.
(g)	Aboveground flow lines must be supported consistent with the requirements of … ASME B31.4-2002.	ASME B31.4 – 2002	Aboveground flow line support design is consistent with the standard's requirements.
(h)(1)	Verify compliance with [18 AAC 75.047]…(c) … for corrosion control measures … by documentation of dates and locations of inspections and tests; inspections and test data evaluation including analysis of weight loss coupons and electrical resistance probes; and corrosion inspections; data and analysis of chemical optimization activities; analysis of corrosion trends that affect the fitness for service of the flow line; and a list and description of repair activities undertaken.	None	BPXA internal database documents corrosion control and maintenance.
(h)(2)	Verify compliance with [18 AAC 75.047]… (d)(2) … for a preventative maintenance program by documentation to validate the effectiveness of that program, including the procedures for program implementation, dates and locations of inspections and tests; inspections and test data evaluation including analysis, pipewall thickness measurements and remaining life calculations; and internal audit procedures of the program, including descriptions of controls and corrections for identified defects.	None	BPXA internal database documents corrosion control and maintenance.

* API 570, Second Edition, October 1998, Addendum 1, February 2000, Addendum 2, December 2001, and Addendum 3, August 2003.

BURIED FLOW LINE INSPECTION AND MAINTENANCE

Consistent with 18 AAC 75.047(i), buried is defined as covered or in contact with soil. Buried flow lines are not present.

2.1.8 LEAK DETECTION, MONITORING, AND OPERATING REQUIREMENTS FOR CRUDE OIL TRANSMISSION PIPELINES [18 AAC 75.055]

The Endicott crude oil transmission pipeline moves oil from Endicott to Pump Station 1, as shown in Figure B-4 in Appendix B. The crude oil transmission pipeline is equipped with a system capable of detecting a leak with a daily rate equal to one percent of daily throughput, as required by 18 AAC 75.055(a)(1).

Flow of the Endicott and Badami pipelines is verified at least once every 24 hours. The flow of incoming oil can be stopped on both pipelines within one hour after detection of spill. The Eastern Offtake Center Operator proceeds through a series of steps to determine the cause of the alarm. Ground-based surveillance may be requested. Verification of a leak would facilitate pipeline shut in. See also Section 2.5.7.

The turbine meters at Badami and Endicott and the Endicott pipeline custody meter at Pump Station 1 measure flow daily. The pipeline loop is balanced out at least once every 24 hours.

The Badami pipeline is equipped with a system capable of detecting a leak with a daily rate equal to one percent of daily throughput when feasible, as required by 18 AAC 75.055(a)(1). Under the current pipeline configuration, that sensitivity is feasible at throughputs of 3,000 barrels of oil per day (bopd) and greater. Lesser throughput rates mean that inventory changes associated with cooling oil could be reliably distinguished from leaks only at leak volumes greater than 1 percent of daily throughput.

See Section 2.5.6 for a description of aerial surveillance.

2.1.9 OIL STORAGE TANKS [18 AAC 75.066]

This section describes the management of ADEC-regulated tanks, i.e., oil tanks greater than 10,000-gallon capacity. Part 3 provides information for oil storage tanks greater than 10,000 gallons as required by 18 AAC 75.425(e)(3)(A). Field-constructed oil storage tanks are not present at Endicott or the Badami pipeline.

Containers are constructed of materials compatible with the stored products. Tanks for processing drilling muds and cuttings on drill rigs are not oil storage tanks.

INSPECTIONS

Oil storage tanks greater than 10,000 gallons in service and on BPXA leases are maintained and inspected consistent with American Petroleum Institute (API) Standard 653, third edition 2001, and Addendum 1, September 2003, or API Recommended Practice 12R1, fifth edition 1997.

Inspections and maintenance of shop-built tanks follow Steel Tank Institute (STI) SP001 or API 653 or another equivalent approved by ADEC. Inspection intervals for shop-built tanks may be based on similar service and risk-based inspection procedures outlined in API 653.

Records of inspections, tests, maintenance and repairs of shop-built ADEC-regulated tanks are kept for five years. Copies of these records are provided to ADEC upon request.

CONSTRUCTION

Shop-built, ADEC-regulated oil tanks first placed in service before December 30, 2008, are not subject to an ADEC requirement for construction standards.

Six shop-built tanks were placed on the Satellite Drilling Island (SDI) in 2009; these tanks have not been placed into service and are not subject to the requirements of 18 AAC 75.066.

As required by 18 AAC 75.066(g), ADEC-regulated oil storage tanks greater than 10,000 gallons have one or more of the following overfill protection means:

- High liquid level alarm with signals that sound and display, or
- High liquid level automatic pump shutoff device, or
- A means to immediately determine the tank's liquid level, including close monitoring of the liquid level during a transfer to the tank, or
- Another system approved by ADEC which notifies the operator of high liquid level.

OVERFILL PROTECTION DEVICE INSPECTIONS

Overfill protection devices on ADEC-regulated tanks are tested before each transfer to them or monthly, whichever is less frequent. See the tank tables in Part 3 and Appendix A.

A test of the overfill protection device is a manipulation of part of the system for the purpose of eliciting a response. Devices are tested in a variety of ways depending on how they are used and frequency of use. Overfill protection devices are tested by any of the following:

- level transmitter calibration;
- level transmitter calibration with annunciation of the alarm;
- level transmitter calibration with annunciation of the alarm and strapping;
- testing the level indicators and alarms by lowering the high liquid level alarm set point to below the actual liquid level to force a false alarm;
- checking the circuit continuity;
- changing the level in the tank to verify the level transmitter or alarm enunciator;
- strapping to calibrate the continuous level indicator in the control room; and
- comparing sight glasses to a measured volume.

Some methods are part of regular preventative maintenance procedures.

2.1.10 SECONDARY CONTAINMENT AREAS FOR ADEC OIL STORAGE TANKS AND TANK TRUCK LOADING AND PERMANENT UNLOADING AREAS [18 AAC 75.075]

OIL STORAGE TANKS SECONDARY CONTAINMENT

Single-wall oil storage tanks greater than 10,000 gallons are located within secondary containment areas with the capacity to hold the volume of the largest tank plus precipitation, unless there is a waiver by ADEC.

Secondary containment areas are constructed of bermed, diked, or retaining walls. The containment areas are lined with materials resistant to damage and are sufficiently impermeable. The selection of liners for oil tank pits provides material with demonstrated compatibility with particular products, resistance to cold cracking, and resistance to rough handling.

Shop-fabricated tanks greater than 10,000 gallons may be moved for operational needs, such as well work. For portable single-wall oil storage tanks, secondary containment is constructed to serve for the duration of their use in one location and reconstructed at further locations. For example, well service tanks typically are underlain with Herculite liner supported at the perimeter by tubular metal frames. ADEC-regulated portable tanks have secondary containment with capacity more than that of the tank's shell capacity. For example, many single ADEC-regulated portable single-wall well service tanks are typically served by secondary containment liners 40 feet by 50 feet and two-and-a-half feet tall calculated to provide approximately 890-barrel capacity.

The outer wall of a double-walled aboveground oil storage tank is considered secondary containment. Additional bermed, lined, secondary containment is not required for tanks of a vaulted, self-diked or double-walled design if they are equipped with catchments that positively hold overflow due to tank overfill or divert it into an integral secondary containment area [18 AAC 75.075(h)]. The overfill catchment may be of welded construction or other fixed, e.g., stationary, containment such as a lined pit.

Secondary containment systems are maintained free of debris, vegetation, and other materials or conditions, including excessive accumulated water that interferes with the effectiveness of the system as required by 18 AAC 75.075. Water in the containment areas freezes which adds a smooth layer of ice to facilitate removal of leaks and spills in the winter. Some fabric liner bottoms are held in place with a gravel layer.

Facility personnel visually check for the presence of oil leaks or spills within secondary containments for single-wall ADEC-regulated oil storage tanks daily. The containments are further inspected for debris and vegetation, proper alignment and operation of drain valves, visible signs of oil leaks or spills, and defects or failures (e.g., tears and holes) weekly. The records of daily and weekly inspections are entered in the PRIDE database or other records.

Double-wall tanks holding oil and not required to have further secondary containment are inspected for oil leaks into the interstitial space monthly. See Table 2-8 for visual inspection description.

Snowmelt runoff, debris, and accumulated rainwater in outdoor secondary containment for ADEC-regulated oil tanks are vacuumed out, or dewatered, and disposed of. Stormwater program records are kept describing the dewatering to land or water from individual ADEC-regulated secondary containments. The records note whether sheens were present.

Portable oil storage tanks that are temporarily not in use and operationally empty are stacked without secondary containment in designated storage areas on gravel pads. The stored tanks remain subject to the integrity inspections according to the BPXA tank integrity management program.

BPXA notifies ADEC in writing within 24 hours if a significant change occurs in or is made to an ADEC-regulated tank's secondary containment system and if, as a result of the change, the system no longer meets the ADEC performance requirement [18 AAC 75.475(d)].

TANK TRUCK LOADING AND PERMANENT UNLOADING AREAS SECONDARY CONTAINMENT

ADEC-regulated tank truck loading and permanent unloading areas are identified in Table 3-1. ADEC–regulated tank truck loading and permanent unloading areas are those involving frequent transfers of oil to and from ADEC-regulated tanks. Truck sites with infrequent use, seasonal use, for temporary projects or emergency generators, solely for tank maintenance, or serving non-ADEC regulated tanks are not regulated tank truck loading and permanent unloading areas.

The tank truck loading and permanent unloading areas meet 18 AAC 75.075(g) by several means. They have secondary containment designed to contain the maximum capacity (e.g., gross volume) of the largest single compartments of the tank trucks using each containment area. Those secondary containment structures are paved, surfaced or lined with sufficiently impermeable materials.

The tank truck loading and permanent unloading areas' secondary containments are maintained free of debris, vegetation, excessive accumulated water, or other materials or conditions that interfere with the effectiveness of the system. The areas have warning signs or wheel chocks to prevent premature vehicular movement.

The tank truck loading and permanent unloading areas' secondary containments are visually inspected before transfers or at least monthly, whichever is less frequent.

2.1.11 REQUIREMENTS FOR FACILITY OIL PIPING [18 AAC 75.080]

Table 2-2 summarizes BPXA's methods for meeting the requirements of 18 AAC 75.080.

TABLE 2-2: FACILITY OIL PIPING COMPLIANCE

CITATION 18 AAC 75.080	REGULATORY STANDARD	ADEC-REQUIRED ENGINEERING STANDARD	HOW THE STANDARD IS MET
(b)	Maintain metallic facility oil piping in accordance with a corrosion control program.	None	Corrosion control of facility piping is guided by BPXA internal procedures.
(c)	Facility oil piping placed in service after December 30, 2008 is designed and constructed in accordance with …ASME B31.3-2004 … ASME B31.4-2002 … or ASME B31.8-2003	ASME B31.3 – 2004 ASME B31.4 – 2002 ASME B31.8 – 2003	BPXA internal guidance stipulates design procedures in accordance with the standard.
(d)	Buried metallic facility oil piping placed in service between May 14, 1992 and December 30, 2008, is protected from corrosion by installing protective coating and cathodic protection appropriate for local soil conditions and is of all welded construction with no clamped, threaded, or similar connections for lines larger than a one inch nominal pipe size.	None	Endicott does not have buried facility piping placed in service between May 14, 1992, and December 30, 2008.
(e)	Buried facility oil piping placed in service after December 30, 2008, is of all welded construction with no clamped, threaded, or similar connections for lines larger than one inch nominal pipe size; and Unless constructed of a corrosion-resistant material approved by the department, is protected from corrosion by installing protective coating; and cathodically protected.	None	BPXA internal guidance stipulates design procedures consistent with the regulation.
(f)	Cathodic protection systems installed after 2008 meet NACE RP0169-2002, designed by a corrosion expert, and installation supervised by a corrosion expert.	NACE RP0169 – 2002	No equipment is subject to the requirement.
(g)	If a piping segment of a buried facility oil piping installation is exposed for any reason, the segment is carefully examined for damaged coating or corroded piping in accordance with Section 9.2.6 of …API 570 …If active corrosion is found during that examination, the owner or operator shall implement actions for control of future corrosion; and significant repairs or replacements must meet the requirements of [ADEC's 18 AAC 75.080] (c) and (e)	API 570*, Section 9.2.6	Buried facility oil piping is inspected for damage and corrosion any time it is exposed in accordance with API 570, Section 9.2.6. If active corrosion is found, corrosion control is implemented. Buried facility oil piping replacement will be corrosion-protected and welded with no clamped or threaded connections in accordance with 18 AAC 75.080(d).
(h)	Buried facility oil piping installation of metallic construction without cathodic protection shall ensure that the piping is electrically inspected by a corrosion expert for active corrosion at least once every three years, but with intervals between inspections not exceeding 39 months; and in areas in which active corrosion is found, cathodically protected.	None	Buried facility oil piping of metallic construction without cathodic protection is electrically inspected by a corrosion expert for active corrosion at least once every three years, with intervals between inspections not exceeding 39 months.

TABLE 2-2 (CONTINUED): FACILITY OIL PIPING COMPLIANCE

CITATION 18 AAC 75.080	REGULATORY STANDARD	ADEC-REQUIRED ENGINEERING STANDARD	HOW THE STANDARD IS MET
(i)	Aboveground facility oil piping is supported consistent with the requirements of Paragraph 321 of …ASME B31.3-2004.	ASME B31.3 – 2004	Aboveground facility piping support design is consistent with the requirements of the ASME code used to design the piping.
(j)	Facility oil piping is maintained and inspected under a program developed in accordance with API 570.	API 570*	Inspection and repair practices are in accordance with API 570 or an alternative approved by ADEC.
(k)	Cathodic protection systems consistent with NACE RP0169, Section 10, survey, maintain test leads.	NACE RP0169, Section 10	No equipment is subject to this requirement. The buried facility piping at Endicott is not long enough (less than 100 feet) to require test stations.
(l)	Aboveground facility piping … is protected from atmospheric corrosion by … protective coating … use of corrosion-resistance material … or … demonstrate …by…experience… that atmospheric corrosion of GPB facility piping…does not affect the safe operation of the piping before the next scheduled inspection.	None	Experience shows that atmospheric corrosion of aboveground facility oil piping does not affect safe operation between inspections.
(m)	At a soil-to-air interface, piping is protected against external corrosion through the application of a protective coating or …corrosion-resistant materials.	None	Piping's soil-to-air interface has coating or corrosion-resistant materials.
(n)	Aboveground facility oil piping and valves must ensure that the piping and valves are visually checked for leaks or damage during routine operations or at least monthly, and appropriately protected from damage by vehicles.	None	BPXA procedures call for regular visual inspection of pipelines. Traffic barriers are in place where appropriate.
(o)	Facility oil piping that is removed from service for more than one year shall [be] free of accumulated oil, identified as to origin, marked on the exterior with the words "Out of Service" and the date taken out of service, secured in a manner to prevent unauthorized use, and either blank flanged or otherwise isolated from the system. Notify the department when facility oil piping is removed from service and when the actions required…are completed. Removed from service means the pipe is not used for its intended purpose of moving oil and is no longer maintained or inspected per API 570.	None	Facility piping removed from service for more than one year is free of accumulated oil, identified as to origin, marked with the words "Out of Service" or "Removed from Service" and the date taken out of service, secured to prevent un-authorized use, and blank-flanged or isolated from the system. Notifications of the out-of-service status are made by way of BPXA Pipeline group reports to ADEC SPAR IPP.

* API 570, Second Edition, October 1998, Addendum 1, February 2000, Addendum 2, December 2001, and Addendum 3, August 2003.

BURIED FACILITY OIL PIPING

Consistent with 18 AAC 75.080(p), buried is defined as covered or in contact with soil.

Buried facility piping is present at the Endicott fuel transfer area. The 2-inch diesel and gasoline lines are buried for approximately 75 feet (diesel) and 50 feet (gasoline), from the bulk storage area to the fueling area. The lines are coated with a protective wrapping and are cathodically protected. The piping was installed before 1992.

TEMPORARY PIPING

Temporary hardline piping is used for intermittent well testing as an integral part of a separator process unit. It does not meet the definition of facility piping in 18 AAC 75.990(171) and is not subject to ADEC regulations.

2.1.12 FLOW LINES AND FACILITY OIL PIPING [18 AAC 75.047 AND 18 AAC 75.080]

This section addresses BPXA's compliance with the requirements both for flow lines, which transport multi-phase oil between well pads and production facilities, and facility oil piping, which originates from or terminates at an ADEC-regulated oil storage tank or an exploration or production well. Crude oil transmission pipelines (oil transit lines) are outside the scope of this section as they are not considered flow lines or facility oil piping.

Table 2-1 summarizes methods for meeting the requirements of 18 AAC 75.047. Table 2-2 summarizes the methods for meeting the requirements of 18 AAC 75.080.

CORROSION MANAGEMENT PROGRAM

BPXA's corrosion management strategy includes corrosion monitoring, corrosion mitigation, inspections, and fitness-for-service assessments. Flow lines and facility oil piping are in a corrosion control program guided by asset specific corrosion control plans.

CORROSION CONTROL

Corrosion control measures reflect the active or potential corrosion mechanisms in the piping system. For flow line and facility oil piping, they can be broadly subdivided into internal and external corrosion mechanisms. The external corrosion mechanism is constant for all services while the internal differs with service.

Internal Corrosion and Erosion of the Endicott Production System

The Endicott production system transports multiphase fluids (i.e., oil, water, gas), also known as 3-phase flow. The properties of fluids are similar throughout the system, although temperature, pressure, and velocity vary. The water cut, gas-to-oil ratio, and solids content also vary from line to line. Table 2-3 summarizes the significant corrosion mechanisms.

TABLE 2-3: INTERNAL CORROSION MECHANISMS RELEVANT TO PRODUCTION SYSTEM

CORROSION MECHANISM	SEVERITY OF MECHANISM	CONTROL METHOD
Carbon dioxide corrosion	High	Material selection
Flow assisted corrosion	High	Material selection Velocity control
Solid erosion and erosion-corrosion	High	Velocity control Well work and place-on-production procedure Solids monitoring
Chemical attack	High	Material selection Chemical selection Operating procedures Equipment design
Microbiologically influenced corrosion (MIC)	Low	Material selection
Under-deposit/crevice corrosion	Low	Velocity control
Preferential weld corrosion	Low	Fabrication control
Oxygen corrosion	Low	Chemical deaeration

Carbon dioxide corrosion is the primary corrosion mechanism in the production system. The control of carbon dioxide corrosion is achieved primarily through materials selection. The majority of the producing system is constructed from corrosion-resistant duplex stainless steel. The only surface production equipment made of carbon steel is the C-spools that connect the well to the well lines. The C-spools are inspected frequently to assure their integrity and are repaired or replaced as needed. C-spools requiring replacement are being replaced with duplex stainless steel, as the need arises.

Flow assisted corrosion is controlled via material selection and the use of duplex stainless steel. Erosion is associated with extremely high velocities and solids production. Solids production is unpredictable because it is the result of an event downhole, such as the breakdown of a cement job or production of unconsolidated reservoir rock. Velocity limits for erosion control rely on the approach defined in API RP 14E, using the C-factor of 100. Lines are ranked approximately monthly in terms of risk using the ratio V/Ve, where V is the mixture velocity and Ve is the calculated erosion velocity limit. An operating limit of 2.5 is used. These limits are subject to revision as more experience is gained at managing erosion.

Microbiologically influenced corrosion (MIC) has not been accurately quantified in the Endicott production systems. However, sulfate-reducing bacteria and general anaerobic bacteria (GAnB) are present. Control of MIC is through materials selection, the same as carbon dioxide corrosion.

Chemical attack has been associated with highly corrosive scale inhibitor pooling in production pipework during shut-ins. There have also been instances of injection quill failure, leading to contact of the neat (pure) chemical with the pipewall during normal operations. Chemical attack at Endicott is no longer a concern as the scale inhibition program has been discontinued.

Internal Corrosion of the Produced Water System

The produced water injection system is defined as starting at the water outlets off the separation vessels and ending at the reservoir. It includes the process piping, storage tanks, injection pumps, flow lines and well lines that store or transport produced water, and the injection wells. Table 2-4 summarizes the major corrosion mechanisms relevant to the produced water system.

TABLE 2-4: INTERNAL CORROSION MECHANISMS RELEVANT TO PRODUCED WATER INJECTION SYSTEM

CORROSION MECHANISM	SEVERITY OF MECHANISM	CONTROL METHOD
Microbiologically influenced corrosion (MIC)	High	Chemical inh bition Maintenance pigging
Under-deposit/crevice corrosion	High	Velocity control Maintenance pigging
Solid erosion and erosion-corrosion	Medium	Velocity control Solids monitoring
Carbon dioxide corrosion	Low	Chemical inh bition
Preferential weld corrosion	Low	Chemical inh bition Fabrication control
Chemical attack	Low	Chemical selection Operating procedures Equipment design
Galvanic corrosion	Low	Material selection Material isolation
Hydrogen sulfide corrosion Oxygen corrosion	Low	Mechanical deaeration Chemical deaeration

Carbon dioxide corrosion is a significant issue for the upstream system but the oil stabilization process removes the vast majority of the carbon dioxide, substantially reducing its partial pressure in the produced water system. The corrosion inhibitor dosed into the produced water system is fully capable of controlling any residual threat of carbon dioxide corrosion.

MIC is an issue in the injection system because the low fluid velocities in tanks and pipework allow bacteria colonies to become established and thrive. The current corrosion inhibitor is known to be toxic to sulfate-reducing bacteria and general anaerobic bacteria and the bacteria count has decreased. In addition, the Inter-Island Water Line that transports injection water from the production facility to the Satellite Drilling Island is regularly pigged to displace solids and bacteria. Periodic biocide treatment on this line is also conducted.

Controlling External Corrosion

External corrosion is a threat to equipment outside of modules and facilities. It can be subdivided into atmospheric corrosion and corrosion under insulation. No production equipment is buried directly in the tundra. Therefore, external corrosion at pipewall/soil interfaces is not an issue. Atmospheric corrosion in the Arctic is a slow process due to the low relative humidity, lack of rainfall, and low temperatures. External corrosion is only a significant issue for insulated equipment, where the polyurethane foam insulation can trap moisture next to the pipewall. This warm, moist environment, together with the oxygen in the air, can lead to corrosion.

Insulation-and-jacket systems or tape wrap that exclude water serve as one means of protective coating. The insulation systems used on pipelines is a combination of shop-applied polyurethane foam on the linepipe spools with an external galvanized steel jacket. The insulation is completed at weld joints using a range of methods, but involves the application of polyurethane foam and galvanized steel jacketing. This insulation is generally resistant to moisture ingress, except at areas of damage. The major challenge in managing external corrosion is detection. Once it is detected it can be easily and effectively mitigated by removing wet insulation.

Evidence of external corrosion is investigated to determine the extent of corrosion. Pipeline repairs necessitating pipe replacement are cause for an internal inspection of the affected sections of pipe in the immediate vicinity to establish repair boundaries.

EXTERNAL/INTERNAL CORROSION INSPECTION ACTIVITIES

Corrosion inspections are part of the Corrosion Management Program. Corrosion inspection methods include smart pigging, conventional nondestructive testing (NDT) methods, guided wave inspections, and excavation and visual inspection. The technologies are discussed in detail in Part 4.10. Table 2-5 demonstrates the corrosion inspection methods for various ADEC-regulated pipelines. The terms “internal” and “external” inspections are used to describe the purpose of the inspection, i.e., looking for internal or external corrosion, not the inspection method.

Many factors determine the interval between successive inspections. Manufacturer recommendations, state and federal regulations, and safety are key influences in establishing the frequency of inspections. A number of factors contribute to the selection and allocation of inspection resources (frequency of inspection and inspection method) including but not limited to current equipment condition, current known corrosion rate, operational threats associated with fluid type, corrosion mitigation, operation, design, and age of the equipment.

TABLE 2-5: SUMMARY OF PIPELINE CORROSION INSPECTIONS

PIPELINE	NUMBER OF ROAD/ANIMAL CROSSINGS	CORROSION SURVEY METHOD	FREQUENCY
Diesel / Gasoline Lines	2 (direct buried)	NDT, excavation and visual	5 years
Inter-Island Produced Water Flow Line	1	NDT, smart pig and visual	1 to 10 years, depending on method
Production Flow Line (duplex stainless steel)	1	Not applicable	Annually
Facility Oil Piping (produced water)	2	NDT, excavation and visual inspection in vaults	1 to 10 years, depending on method

The three-phase Endicott production flow line is fabricated of duplex stainless steel, which is corrosion-resistant. The produced water facility oil piping at the road crossing between SDI and Main Production Island (MPI) is in a vault, and is visually inspected annually for corrosion.

Corrosion Rate Monitoring Program

The goal of the Corrosion Rate Monitoring (CRM) program is to detect active corrosion in support of corrosion control activities, primarily the chemical inhibition program. The data are complementary to other monitoring data, such as corrosion probes and corrosion coupons. As the primary aim is to determine when corrosion occurs, this program is of fixed scope at fixed inspection intervals. For a typical system, locations are inspected twice per year. The inspections are staggered, with half of the set completed in the first calendar quarter and half in the second. These are repeated in the third and fourth quarters, respectively. Therefore, information regarding the level of corrosion activity in a system is generated every quarter. The CRM program is designed primarily for flow lines; however, it may be adapted to other types of equipment as required. The inspection frequencies may vary dependent upon program need.

Erosion Rate Monitoring Program

The purpose of this program is similar to the Corrosion Rate Monitoring program but is aimed at monitoring erosion activity. Production variables are the driving factor for this damage mechanism (i.e., production rates and solids loading); therefore, inspection is determined by “triggers” such as velocity limits, Well Work (WW), etc. If such triggers are exceeded, inspections are performed on a daily, weekly, or monthly basis depending on the driving factor for placing the equipment in a potential high-risk state. Inspections are continued until confidence is gained that erosion is not occurring. The erosion rate monitoring program is primarily associated with three-phase well lines.

Frequent Inspection Program

Flow lines, well lines, vertical support members (VSM), valves, and gas lines are covered under the Frequent Inspection Program. The goal of the Frequent Inspection Program is to manage mechanical integrity at locations where significant corrosion damage is detected. Locations are added to the Frequent Inspection Program if they are approaching repair, de-rate criteria, or if unusually high corrosion or erosion rates are detected. As the name implies, inspections are performed frequently until the item is repaired, replaced, de-rated, taken out of service, or corrosion/erosion rates are reduced. The inspection interval varies depending on how close the location is to repair/de-rate and the rate of corrosion, but it does not exceed one year.

Comprehensive Integrity Program

The Comprehensive Integrity Program inspection survey applies to flow lines, well lines, and their associated facilities including valves and casings. It is an annual program designed to detect new corrosion mechanisms and new locations of corrosion, and to monitor damage at known locations. The Comprehensive Integrity Program provides an assessment of the extent of degradation and the fitness for service.

Corrosion Under Insulation Inspection Program

Three-phase flow lines and well lines are covered by the Corrosion Under Insulation (CUI) program. A recurring corrosion under insulation inspection and mitigation program has been determined to be the most efficient means of minimizing loss as a result of external corrosion. Piping is inspected for CUI on a frequency between three and five years. Prioritization of inspection surveys is determined by average temperature of the equipment, previous inspection results, age of equipment, or the last time a complete screening process was completed. For the overall program to be successful, the detection and mitigation programs must be linked together.

Walking Speed Surveys

Walking speed surveys consist of visual examinations of piping to identify mechanical integrity deficiencies and bare pipe locations. Anomalies are noted and evaluated by a piping engineer. Walking speed surveys of well lines and flow lines are conducted every five years. As the name implies, observations are made at “walking speed.”

Cased Piping Inspection

Cased piping, meaning below-grade piping installed in casing and not in direct contact with soil, is treated as aboveground piping. There are two types of cased piping: cased piping which is accessible for visual inspection and cased piping that is not.

Examinations of cased piping are achieved through in-line inspection or non-destructive examination technologies such as guided wave or electromagnetic inspection. Guided wave ultrasonic inspections of pipeline crossings involve inspections of the pipeline from each end of the below-grade casing.

Cathodic protection is ineffective where piping is not in contact with soil. As such, cased piping will not be installed with cathodic protection, but rather will be provided with some other method of corrosion protection (e.g. corrosion-resistant alloy or fusion bond epoxy coating).

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

The discharge history of reported oil spills greater than 55 gallons and oil spills of any volume to water or tundra for the period January 1992 through August 2011 is provided in Appendix C and includes the following information:

- Date of discharge,
- Material discharged,
- Estimated amount discharged,
- Description of the spill event,
- Environmental impact, and
- Corrective and preventive actions taken.

The history of reported discharges of volume greater than 55 gallons is maintained in the BPXA spill database for the life of the facility.

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

The potential for oil spills is understood from historical spill data. Table 2-6 summarizes reports of Endicott spills greater than 55 gallons. The historical data assist in identifying operations or equipment that is prone to spills.

Spills associated with operational activities make the largest category of reported spills greater than 55 gallons (66%), followed by equipment problems (24%), and operator error (10%) among oil spills reported January 1992 through August 2011.

TABLE 2-6: ENDICOTT OIL SPILL REPORTS, 1992-2011

CATEGORY	SOURCE	NUMBER OF SPILLS (>55 GALLONS) REPORTED	ESTIMATED CUMULATIVE VOLUME (GALLONS)
Equipment	Fittings	4	983
	Valves	4	655
	Tubing	4	425
	Gaskets/Liners/Thaw Bulbs	4	449
	Overfill/Seals/Nipples	3	473
Operational Activities	Hose	1	110
	O-ring	1	4,410
	Overfill	1	2,695
	Valve	3	359
	Wellbore	1	550
Operator Error	Fluid Transfer	1	840
	Manifold	1	100
	Overfill	1	100
	Vehicle	1	130

Figure 2-1 depicts the percentage of estimated volumes spilled associated with operational activities at Endicott. One O-ring related spill accounts for more than half (nearly 54 percent) of the total estimated volume. Figure 2-2 depicts the percentage of estimated volumes spilled associated with equipment at Endicott.

FIGURE 2-1: REPORTED OIL SPILLS ASSOCIATED WITH OPERATIONAL ACTIVITIES (ESTIMATED % OF TOTAL VOLUME)

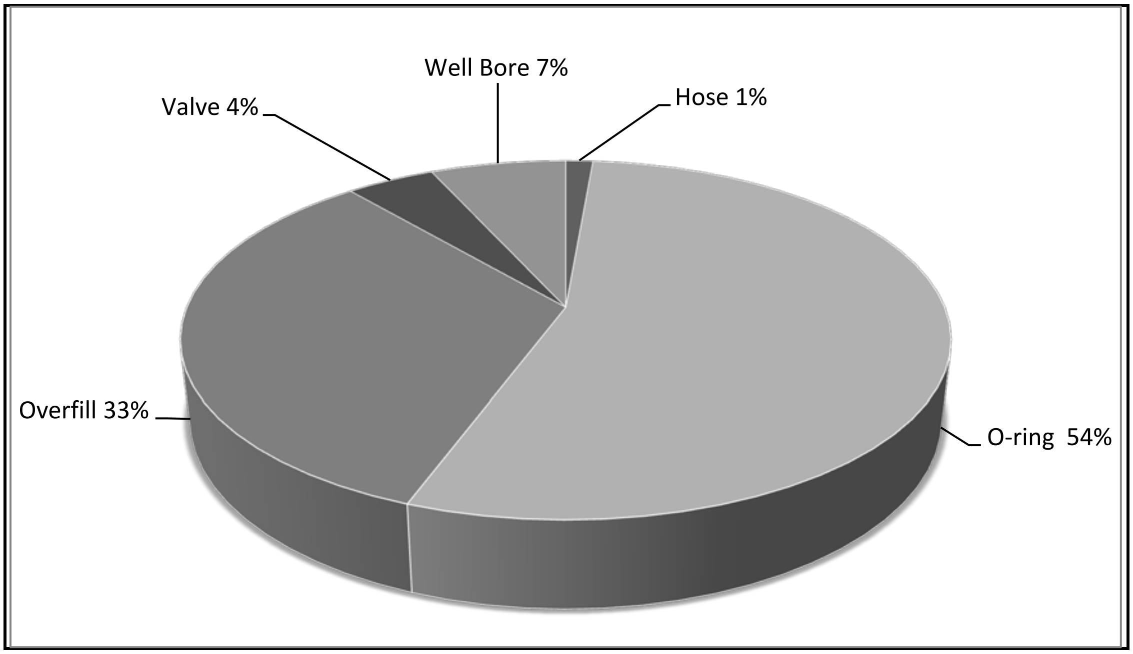
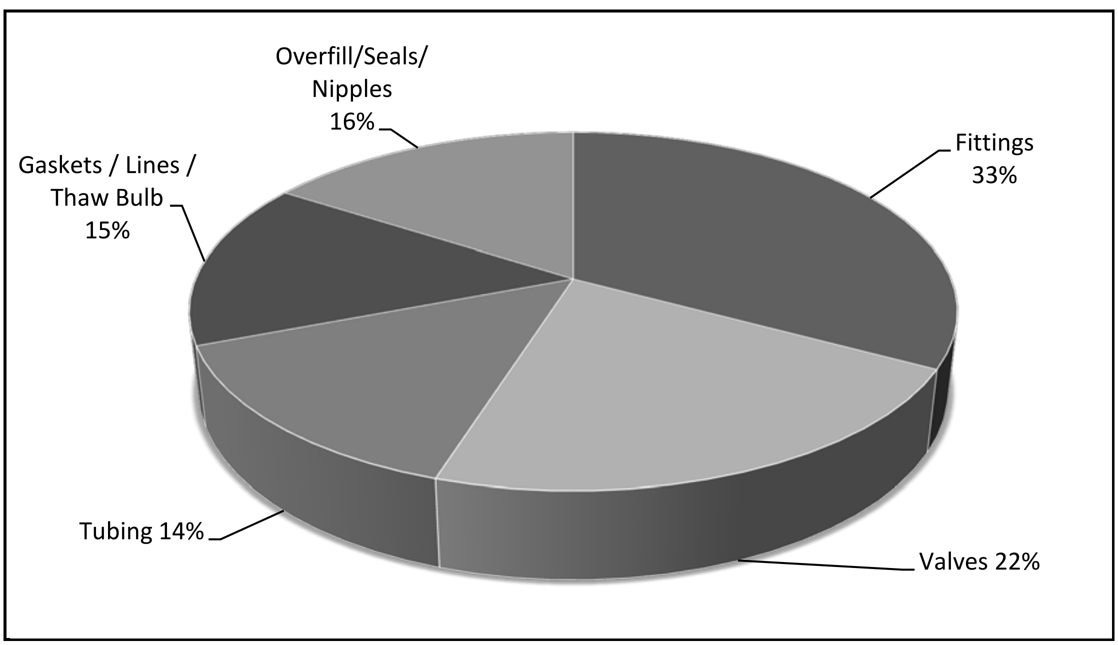


FIGURE 2-2: REPORTED OIL SPILLS ASSOCIATED WITH EQUIPMENT (ESTIMATED % OF TOTAL VOLUME)



Examples of potential oil spills are described in Table 2-7, which summarizes potential pipeline spills and release quantities. Spill prevention actions involve the training, operating procedures, leak detection, inspections, and secondary containment outlined in Part 2.

TABLE 2-7: POTENTIAL SPILLS FROM VARIOUS SOURCES

SOURCE	CAUSE	PRODUCT	SIZE (BARRELS)	DURATION	PREVENTIVE MEASURES
Fuel lines transfer	Rupture	Fuel	500	varies	Berms are provided and liners are used in sensitive areas that may be affected by a spill.
Fuel delivery vehicle	Rupture Broken hose	Fuel	325	Broken hose – instantaneous draining	Unified Fluid Transfer Procedures.
Well	Uncontrolled flow from wellbore	Crude Oil	12,855	857 bopd, 15 days	Well houses, visual surveillance program
Dirty water tank	Tank rupture	Dirty water	4,912	Instantaneous	Secondary containment; overflow protection devices, and tank inspection program.
Crude oil pipeline release	Rupture	Crude Oil	4,854	Instantaneous	Corrosion control program, leak detection system, visual surveillance

Spill prevention actions involve training, operating procedures, leak detection, inspections, and secondary containment outlined in Part 2. BPXA participates proactively in spill prevention programs including campaigns, investigations, and training to increase employee awareness levels.

BPXA North Slope operations employ multiple learning processes as part of the Alaska Incident Investigation program to help prevent potential discharges. Proven techniques, such as “Root Cause Failure Analysis,” are used during the investigation process to ensure the highest value actions are implemented to prevent reoccurrence. Lessons learned are broadly shared across BPXA and the contractor community to promote spill prevention. Depending on the incident, the review team may include personnel responsible for the operation causing the spill, their foreman or supervisor, a safety representative, field environmental compliance personnel, a facility supervisor, and/or a corrosion engineer. The investigation process is aimed at addressing the root cause of the incident and thereby eliminating workplace risk, reducing personnel exposure to spilled materials, preventing reoccurrence of spills, and identifying additional early detection opportunities. Spill investigation results are communicated to BPXA and contractor field personnel to promote spill prevention. Periodically, teams are developed to conduct an analysis of potential trends in spill causes, locations, materials, volumes, and frequencies.

The analysis of these trends offers the opportunity to proactively implement additional continual improvement measures to further reduce the potential for discharge.

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

Conditions specific to BPXA's North Slope operations that potentially increase the risk of an oil spill, and actions taken to reduce the risk of a spill, are as follows:

- Heat may cause gases to expand, increasing the likelihood of discharge. North Slope facilities are engineered to accommodate temperature fluctuations.
- Cold snaps present obvious threats to field operations. North Slope facilities are engineered to withstand arctic conditions.
- Icy roads, white out conditions and changes in traffic patterns may increase the risk of vehicle collisions. BPXA Security's strict adherence to vehicle safety, speed limits, and the posting of warning signs assist in minimizing the potential for vehicular accidents that may result in a spill.
- If the Trans Alaska Pipeline System (TAPS) unexpectedly shuts down the pipeline, the risk to BPXA systems increases. BPXA's advanced communication system enables immediate communication between the TAPS and the North Slope operators, which allows for the coordination of impacts and minimizes the risks due to a shutdown of the pipeline.
- High winds could increase the risk of discharge during fuel transfers. If wind speed appears to pose a threat to communications or hoses, transfer operations will be postponed until the wind subsides.
- As the fields age, the discharge potential increases. To minimize spills related to aging facilities, BPXA uses a computerized preventative maintenance program, has a corrosion control program, does valve inspections in accordance with Alaska Oil and Gas Conservation Commission (AOGCC) regulations, has leak detection monitoring, and conducts regular visual inspections.
- High water and/or ice during break-up could increase the risk of discharge over river crossings. The pipeline support members have been designed to withstand ice conditions expected at the river crossings. High water and ice conditions are monitored during weekly overflights of the Badami pipeline.

The Endicott pipeline has one river crossing at the Sagavanirktok River. To prevent damage to the crossing from ice floes, slots are cut in river ice prior to break-up each year. In addition, river water levels are monitored during high water to ensure that lateral bridge support members do not become submerged. The crossing is observed daily by Security personnel who are responsible for reporting abnormal conditions.

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

2.5.1 DISCHARGE DETECTION FOR DRILLING OPERATIONS AT ENDICOTT

Each drilling rig has a system of controls, monitors, alarms and procedures to assist in the early detection of potential discharges. For both downhole and surface operations, these detection systems include automated monitoring devices as well as standard operating procedures governing the monitoring of fluids.

During downhole operations, much of the discharge detection effort centers on well control with an emphasis on detecting wellbore influxes (kicks). The primary control to prevent a discharge associated with a kick is the density of the hydrostatic column of drilling fluid in the wellbore. The drilling fluid density and other critical parameters are closely monitored by drilling fluid specialists and trained members of the rig crew. Modifications to the mud density are made in accordance with the AOGCC-approved well plan to maintain the proper fluid density at various intervals. The AOGCC requires frequent documented testing of these safety systems and such tests are normally witnessed and verified by AOGCC field representatives.

For surface operations, discharge detection systems use automated equipment, visual, audio or manual detection in combination with policies and procedures governing the handling and containment of fluids. Rig pit systems are equipped with pit volume totalizers that constantly monitor and record pit volume gains and losses. Unexpected gains or losses of drilling fluids initiate alarms, which sets in motion initial crew responses to secure the well. The well is monitored to further identify the cause of the event.

Rig surface systems are continuously monitored for external leakage. Fluid transfers associated with drilling operations are carefully planned, permitted and monitored using fluid transfer guidelines. Adherence to these procedures assists in detection of spills associated with fluid transfer operations.

2.5.2 DISCHARGE DETECTION FOR WELLS

(b) (7)(F)

[redacted]

2.5.3 DISCHARGE DETECTION FOR FLOW LINES AND FACILITY OIL PIPING

Lines from oil-producing wells are equipped with low-pressure transmitters used to isolate producing wells in the event of a line rupture. If the pressure in the line drops below thresholds the line shuts in. Small leaks that would not activate the low-pressure switch would be identified by operations personnel performing routine checks. Given that production fluids are mostly gas and water, with smaller amounts of oil, leaks would involve relatively large amounts of visible steam and gas more easily identified by both sight and sound.

2.5.4 AUTOMATED METHODS OF DISCHARGE DETECTION

(b) (7)(F)

[redacted]

2.5.5 DISCHARGE DETECTION FOR OIL STORAGE TANKS

Endicott stationary tanks are aboveground and mounted on modules or skids within secondary containment. Additional containment is provided via overflow lines to the secondary containment basins. The tanks are fitted with a level transmitter for control room monitoring of tank liquid levels. The tanks are visually inspected as described in Table 2-8.

Portable tanks may be used for oil storage, well work and dewatering operations. The tanks are monitored while they are in use and during fluid transfers. The tanks' secondary containments are visually inspected as described in Table 2-8 when the tanks are storing oil.

Double-walled ADEC-regulated shop-built tanks are equipped with an interstitial monitoring system, e.g., sight glass, view port or drain port, that enables an outside observer to detect oil leaks and water accumulations [18 AAC 75.066(e)(1)].

2.5.6 CRUDE OIL TRANSMISSION PIPELINES DISCHARGE DETECTION

(b) (7)(F)

[redacted]

(b) (7)(F)

[redacted]

(b) (7)(F)

[redacted]

2.5.7 VISUAL INSPECTIONS FOR DISCHARGE DETECTION

Table 2-8 summarizes the visual inspections performed on regulated equipment.

TABLE 2-8: ADEC VISUAL SURVEILLANCE SCHEDULE

EQUIPMENT	RESPONSIBLE POSITION	REGULATING AGENCY	INSPECTION	FREQUENCY	REGULATORY CITATION	RECORDKEEPING
Oil Storage Tanks, 55 gallons or greater For tanks >10,000 gallons, see Table 3-1 and Appendix A.	Endicott O&M Team Lead	ADEC	Visual inspection of external conditions of oil storage tanks >10,000 gallons in operation	Monthly	18 AAC 75.066.	PRIDE or Figure A in BPXA's *Criteria for Tank Integrity Management Program* (CRT-AK-06-96). Retain for five years.
Wastewater Tank T-E3-1802	Endicott O&M Team Lead	ADEC	Visual inspection of tank	Every 12 hours	See ADEC waiver letter dated December 17, 1996 in Section 2.6.	Daily log
Secondary Containment Areas at Regulated Tanks	Endicott O&M Team Lead	ADEC	Visual inspection for tank oil leaks or spills, defects, vegetation and debris.	Daily for leaks or spills without record, unless precluded by safety or weather. Weekly with record for leaks or spills, defects, and interference by debris or vegetation, unless precluded by safety or weather.	18 AAC 75.075(c)	PRIDE or Appendix B form in ADEC Secondary Containment Inspection Procedure. Retain for five years. During Phase 2 and Phase 3 conditions, the inspection form will be noted with “Wx” or “No safe access”.
Secondary Containment at ADEC Tank Truck Loading and Permanent Unloading Areas	Endicott O&M Team Lead	ADEC	Visual Inspection	Monthly	18 AAC 75.075(g)	PRIDE or Appendix B form in ADEC Secondary Containment Inspection Procedure. Retain for five years. During Phase 2 and Phase 3 conditions, the inspection form will be noted with “Wx” or “No safe access”.
Overfill protection device on oil storage tanks >10,000 gallons	Endicott O&M Team Lead	ADEC	Testing of overfill protection device	Monthly or before each transfer, whichever is less frequent.	18 AAC 75.066(h)	PRIDE or Figure A in BPXA's Criteria for Tank Integrity Management Program (CRT-AK-06-96). Retain for five years.

TABLE 2-8 (CONTINUED): ADEC VISUAL SURVEILLANCE SCHEDULE

EQUIPMENT	RESPONSIBLE POSITION	REGULATING AGENCY	INSPECTION	FREQUENCY	REGULATORY CITATION	RECORDKEEPING
Aboveground regulated oil piping and valves.	Endicott O&M TL	ADEC	Visual inspection of vis ble oil piping and valves for leaks and damage.	Monthly	18 AAC 75.080(n)(1)	Visual field inspection form; Daily field shift log; Wells daily review sheet. Retain for five years.
Badami Crude Oil Transmission Pipeline	Endicott O&M TL	ADEC	Aerial surveillance	Weekly unless precluded by safety or weather	18 AAC 75.055(a)(3)	Aerial surveillance form
Endicott Crude Oil Transmission Pipeline	Endicott Security	DOT	Surveillance of sales oil pipeline right of way surface conditions	26 times a year, not to exceed 3 weeks between surveillances	49 CFR 195.412(a)	DOT Pipeline Inspection Checklist Report

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

Waivers follow this page. Waiver content is as follows:

- Flow Line Marker Waiver for Endicott-Badami. (September 12, 2007).
- Waiver of Marking Out-of-Service Facility Piping (March 26, 2009).
- Waiver (Revised) of Daily Secondary Containment Area Inspection Requirements during Bad Weather at Greater Prudhoe Bay, Milne Point, and Endicott and Badami (November 3, 2011).
- Waiver of Secondary Containment for [Endicott] Waste Water Tank T-E3-1802 (March 1, 2013).

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DEPT. OF ENVIRONMENTAL CONSERVATION
DIVISION OF SPILL PREVENTION AND RESPONSE
INDUSTRY PREPAREDNESS PROGRAM
Exploration Production & Refineries

November 3, 2011

File No: 305.35 BPXA/GPB
File No: 305.35 BPXA/MPU
File No: 305.35 BPXA/End-Bad

Mike Bronson
BP Exploration (Alaska), Inc.
P.O. Box 196612
Anchorage, AK 99519-6612

Subject: **BP Exploration (Alaska) Inc. Oil Discharge Prevention and Contingency Plans; Waiver Approval (Revised) for the following Plans:**
Endicott/Badami, ADEC Plan No. 06-CP-4130
Greater Prudhoe Bay, ADEC Plan No. 06-CP-5079
Milne Point Unit, ADEC Plan No. 10-CP-4132

Dear Mr. Bronson:

The Alaska Department of Environmental Conservation (department) has reviewed your February 14, 2005 request for a waiver of the daily secondary containment area (SCA) inspection requirements of 18 AAC 75.075(c) at facilities covered by the three Oil Discharge Prevention and Contingency Plans (plans) referenced above during Phase 2 and 3 weather conditions. Safety of the inspectors is the highest priority for the department, and we understand that conducting these inspections during occasional severe weather on the North Slope could be hazardous.

Phase 2 weather conditions restricts vehicle travel to convoys only, and foot travel is allowed only with a supervisor's consent. Level II road conditions include moderate to heavily drifting snow, water over the road, sheet ice, and blowing snow. Phase 3 weather conditions allows only critical and emergency travel with heavy equipment escorts. Level III road condition examples include roadways that are completely drifted over, washouts, or road or construction work closing the access roadway. Once the severe weather conditions have subsided, it may take a day or two for snow removal crews to clear the snow from the access roads, again precluding inspections.

When weather precludes conducting the daily inspections, the tank liquid level indicators on most tanks can be monitored in the control room.

We recognize that other agencies with similar inspection requirements have weather and safety allowances, such as the Alaska Oil & Gas Conservation Commission and the North Slope Borough. In fact, our own regulations for crude oil transmission pipeline system weekly overflights include a provision for safety or weather conditions [18 AAC 75.055(a)(3)].

Based on the above information, the department is granting the waiver for SCAs located at the referenced facilities during Phase 2 and 3 weather conditions and associated road conditions. This waiver is subject to the following conditions:

1. For each day that inspections are precluded by weather or road conditions, the inspection record will include a notation that such conditions prevented the inspection, such as "Wx" or "No safe access" with a description of the condition.
2. Copies of the security logs that record Phase 2 and 3 times will be made available to the department upon request for those days in which inspections were precluded.
3. This letter supersedes the March 4, 2005 waiver letter, which should be replaced in the plan with this letter at the next routine update.

This waiver does not exempt BP Exploration (Alaska) Inc. (BPXA) 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 BPXA does not comply with the conditions of this waiver

If you have questions or need assistance, please contact Karen McDermott at 269-7569.

Sincerely,

Scott Pexton

Scott Pexton
Section Manager

Enclosure: Waiver, March 4, 2005

Electronic cc:
Laurie Silfven, ADEC
Karen McDermott, ADEC
Jeanne Swartz, ADEC
Tom DeRuyter, ADEC

THE STATE of ALASKA

GOVERNOR SEAN PARNELL

Department of Environmental Conservation

DIVISION OF SPILL PREVENTION & RESPONSE
INDUSTRY PREPAREDNESS PROGRAM
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March 1, 2013

File No.: 305.35
BPXA (Endicott)

Eppie Hogan
Crisis Management Coordinator
BP Exploration (Alaska) Inc.
P.O. Box 196612
Anchorage, AK 99519-6612

Subject: **BP Exploration (Alaska) Inc. Oil Discharge Prevention and Contingency Plan for Endicott. Plan No. 11-CP-4130; Waiver of Secondary Containment for Tank T-E3-1802**

Dear Ms. Hogan:

The Alaska Department of Environmental Conservation (department) has reviewed your request for a waiver dated February 11, 2013 regarding the Secondary Containment Area (SCA) serving Waste Water Tank T-E3-1802 and the requirements of 18 AAC 75.075. The department may waive a SCA 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 [18 AAC 75.015(a)].

BP Exploration (Alaska) Inc. (BPXA) is requesting to rescind the December 17, 1996 waiver pertaining to the twice daily visual inspections requirement of the Tank T-E3-1802 area and is requesting a new waiver granting only one visual inspection within a 24 hours period. All other conditions of the1996 waiver would be retained and are described below. BPXA provided the following information to support the request:

- There is no history of a spill from this tank
- The average tank level is maintained at approximately 10% of capacity; the fluid level is monitored continuously in the control room
- The tank is set to alarm with the fluid level reaches 12%, and
- The tank is highlighted in the Oil Discharge Prevention and Contingency Plan (plan) within the response section, which describes in detail how BPXA would respond to a catastrophic rupture of T-E3-1802

The waiver is still subject to the following conditions as stated in the 1996 waiver, with the following change:

- A routine visual inspection of the tank must be conducted by facility personnel at a minimum of every 24 hours, weather permitting.
- The tank must be operated at all times in a manner consistent with minimizing the oil volume contained within the tank.
- In accordance with 18 AAC 75.065(k), monthly inspections and annual testing of the overfill protection device, including liquid level alarms and valves, associated with the tanks must be performed.
- The tank must be internally inspected at a minimum every ten years in accordance with API 653.
- The plan must be revised at the next routine update to include this waiver approval information to ensure this waiver is document in the plan.
- Spill kits maintained onsite.

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

If you have any questions, please contact Karen McDermott at (907) 269-7569 or karen.mcdermott@alaska.gov or contact me at (907) 269-7580 or graham.wood@alaska.gov.

Sincerely,

Graham Wood
Section Manager

Electronic cc:

Karen McDermott, ADEC
Tom DeRuyter, ADEC
John Ebel, ADEC
Chuck Wheat, BPXA
Eppie Hogan, BPXA

STATE OF ALASKA

SARAH PALIN, GOVERNOR

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September 12, 2007

File No.: 305.35
(BPXA – GPB, End, Milne)

Glen Pomeroy
BP Exploration (Alaska)
P.O. Box 196612
Anchorage, AK 99519-6612

Subject: **BP Exploration (Alaska) Inc. (BPXA) Oil Discharge Prevention and Contingency Plans. Flow Line Marker Waiver for the Following Plans:**
Endicott/Badami, ADEC Plan No. 06-CP-4130
Greater Prudhoe Bay, ADEC Plan No. 06-CP-5079
Milne Point Unit, ADEC Plan No. 06-CP-4132

Dear Mr. Pomeroy:

The Alaska Department of Environmental Conservation (ADEC) has reviewed your July 27, 2007 request for a waiver from the flow line marker requirements in 18 AAC 75.047(e) for Endicott, Greater Prudhoe Bay, and Milne Point facilities. Additional information was given in a follow-up phone call with you on August 24 and in a meeting with Mary Cocklan-Vendl and Eppie Hogan on August 30, 2007.

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. BPXA 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 – 18 AAC 75.085.

To meet the intent of 18 AAC 75.047(e), BPXA is developing a set of field maps identifying the location of each cross-country flow line for use by security, surveillance, and other personnel during routine and emergency operations. Based on the draft field maps brought in for our meeting, the scheduled flow line markers will be spaced with sufficient frequency that additional marking where flow lines approach drill pads or other infrastructure is not deemed necessary.

ADEC approves this waiver based on the following condition:

- BPXA must finalize a set of field maps identifying the location of each cross-country flow line for use by security, surveillance, and other personnel during routine and emergency operations and must provide ADEC with a set of the maps and provide updates as they occur.

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

Sincerely,

Laurie Silfven

Laurie Silfven
Acting Section Manager

cc: Betty Schorr, ADEC, IPP Program Manager
Graham Wood, ADEC, EPR
Tanya Verbyla, ADEC, EPR
Gary Evans, ADEC, EPR
Ed Meggert, ADEC, PERP Fairbanks
Mike Bronson, BPXA
Gordon Brower, North Slope Borough
Carol Fries, ADNR, Anchorage
Jack Winters/Mac McLean, ADNR, Fairbanks
Carl Lautenberger, EPA
Capt. Mark DeVries, USCG
Melanie Barber, USDOT-RSPA
Todd Nichols, ADFG, Fairbanks
Christy Bohl, MMS
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Pam Miller, Northern Alaska Environmental Center
Susan Harvey, Harvey Consulting
Legal Director, Trustees for Alaska

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March 26, 2009

File No.: 305.35
(BPXA – GPB, End,
Milne, Northstar)

Ms. Mary E. Cochlan-Vendl
Pipeline Programs Coordinator
BP Exploration (Alaska) Inc.
P.O. Box 196612
Anchorage, AK 99519-6612

Subject: **BP Exploration (Alaska) Inc. (BPXA) Oil Discharge Prevention and Contingency Plans (Plans). <u>Wording Change for Marking Facility Piping – Waiver for the Following Plans:</u>**
Endicott/Badami, ADEC Plan No. 06-CP-4130
Greater Prudhoe Bay, ADEC Plan No. 06-CP-5079
Milne Point Unit, ADEC Plan No. 06-CP-4132
Northstar, ADEC Plan No. 06-CP-4136

Dear Ms. Cochlan-Vendl:

The Alaska Department of Environmental Conservation (ADEC) has reviewed your March 25, 2009 request for a waiver from the facility piping marking requirements in 18 AAC 75.080(o) for BPXA's North Slope facilities associated with the above-listed plans. In addition to other requirements, 18 AAC 75.080(o) specifies that facility oil piping removed from service for more than one year be marked with the words "Out of Service" and the date taken out of service. BPXA has requested our approval to use the wording "Removed From Service" rather than "Out of Service."

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 – 18 AAC 75.085. Since ADEC considers the two phrases to be equivalent in meaning and since the wording is used interchangeably in our regulations, ADEC approves this waiver request.

If you have any question, please contact Laurie Silfven at (907) 269-7540 or me at (907) 269-3054.

Sincerely,

Betty Schorr
Program Manager

cc: Laurie Silfven, ADEC, EPR
Graham Wood, ADEC, EPR
Bob Tisserand, ADEC, EPR
Gary Evans, ADEC, EPR
Sam Saengsudham, ADEC, PTI
Ed Meggert, ADEC, PERP Fairbanks
Mike Bronson, BPXA
Glen Pomeroy, BPXA

PART 3. SUPPLEMENTAL INFORMATION [18 AAC 75.425(e)(3)]

3.1 FACILITY DESCRIPTION AND OPERATIONAL OVERVIEW [18 AAC 75.425(e)(3)(A)]

3.1.1 FACILITY OWNERSHIP AND GENERAL SITE DESCRIPTION

Endicott ownership is as follows:

- BP Exploration (Alaska) Inc. (BPXA) 67.92 percent
- ExxonMobil 21.02 percent
- Union Oil Company of California 10.52 percent
- NANA Regional Corp. 0.39 percent
- Doyon, Ltd. 0.13 percent
- ConocoPhillips Alaska, Inc. 0.02 percent

BPXA operates and BP Transportation (Alaska) Inc. (BPTA) owns the Badami crude oil transmission pipeline.

Endicott facilities and the Badami pipeline are located in the North Slope Borough, Alaska. Facility diagrams are provided in Appendix B.

The Endicott field is offshore of the Alaska North Slope in the Beaufort Sea, about 15 miles east of Prudhoe Bay. Facilities are approximately 2.5 miles seaward of the Sagavanirktok River Delta, shoreward of the barrier islands, in water up to 14 feet deep.

Endicott started producing oil in 1987. The Endicott facility includes three manmade gravel islands in the Beaufort Sea: the Main Production Island (MPI), the Satellite Drilling Island (SDI), and Endeavor Island. The gravel islands provide stable surfaces for drilling and production systems, the base operations center, and support facilities.

A 1.9-mile-long causeway extends from the Sagavanirktok River Delta to Endicott's inter-island causeway. The causeway provides year-round vehicle access from the mainland. Three permanent breaches are installed in the causeway. A 200-foot breach, Little Skookum, is located offshore near the junction of the two causeways. Approximately 550 feet south of the Little Skookum is a 650-foot breach, Resolution. The third breach, Big Skookum, is a 500-foot breach, approximately 1,500 feet from shore. A 1.5-mile gravel approach extends from the southern end of the causeway across the Sagavanirktok River Delta to the Sagavanirktok River Delta uplands, connecting the causeway with the 8-mile gravel access road to Prudhoe Bay (see Figure B-4).

The Badami pipeline originates at the Badami facility located 31 miles east of Deadhorse, Alaska and ties in to the Endicott pipeline (see Figure B-5 in Appendix B).

Vicinity maps of the facilities are provided in the ACS *Technical Manual*, Volume 2, Map Atlas, Sheets 67, 74, and 91 and are incorporated here by reference. Where available, site drainage is inferred based on aerial photography and the drainage diagrams in the atlas.

3.1.2 FACILITY STORAGE CONTAINERS [18 AAC 75.425(e)(3)(A)(i) AND (ii)]

Table 3-1 describes the type, capacity, installation date, design, construction, stored product, inspection date, and other information for each Alaska Department of Environmental Conservation (ADEC)-regulated stationary oil storage tank. Appendix A contains similar information for regulated portable oil storage tanks.

3.1.3 TRANSFER PROCEDURES [18 AAC 75.425(e)(3)(A)(vi)]

Transfer procedures are described in Section 2.1.5.

TABLE 3-1: ENDICOTT REGULATED STATIONARY OIL STORAGE TANK DATA (TANKS GREATER THAN 10,000 GALLONS)

LOCATION SKID TANK EQUIPMENT ID	PRODUCT TYPE ELEVATED OR ON GRADE NOMINAL DESIGN CAPACITY (GALLONS)	FABRICATION/ INSTALLATION DATE CONSTRUCTION STANDARD	INFLOW CONTROL	OVERFILL PROTECTION	LEAK DETECTION SYSTEMS AND	CORROSION PROTECTION	CIC TANK INTEGRITY INSPECTION (API 653) LAST NEXT INSPECTION	TANK SECONDARY CONTAINMENT CAPACITY (GALLONS)	TANK TRUCK LOADING/PERMANENT UNLOADING AREA SECONDARY CONTAINMENT CAPACITY (GALLONS)
Endicott MPI 305 T-E3-1008	(b) (7)(F) [redacted]	1985 API 650 Shop-fabricated	(b) (7)(F) [redacted]	[redacted]	[redacted]	None	Internal: 2009; 2019 External: 2009; 2014	Gravel berm with 45-mil chlorinated polyethylene (CPER) liner Tanks T-E3-1008, T-E3-1102, and T-E3-1103 are on steel skids with steel containment basins that drain to chemical pit. Based on 2008 Dwg: 244,994	Timber dike with polyurea spray-on liner Based on 2008 Dwg: 17,370
Endicott MPI 305 T-E3-1102	[redacted]	1985 API 650 7th Ed. APP J Shop-fabricated	[redacted]	[redacted]	[redacted]	None	Internal: 2007; 2017 External: 2009; 2014		
Endicott MPI 305 T-E3-1103	[redacted]	1985 API 650 7th Ed. APP J Shop-fabricated	[redacted]	[redacted]	[redacted]	None	Internal: 2007; 2017 External: 2012; 2017		
Endicott MPI 305 T-E3-1801	[redacted]	1986 API 650 7th Ed. APP E, J & K Shop-fabricated	[redacted]	[redacted]	[redacted]	None	Internal: 2007; 2017 External: 2012; 2017		
Endicott MPI 401 T-E3-1802	[redacted]	1985 API 620 7th Ed. Shop-fabricated	[redacted]	[redacted]	[redacted]	None	Internal: 2006; 2016 External: 2011; 2016	See December 17, 1996 Waiver	None
Endicott MPI Outside 401 T-E3-1810	[redacted]	2008 API 650 Shop-fabricated open-top tank	[redacted]	[redacted]	[redacted]	Anodes, coating	Internal: 2008; 2013 External: 2008; 2013	Steel dike with spray-on polyurea liner Based on 2008 Dwg: 20,938	Sheet-metal covered timber berm with 30-mil Petroguard VI liner Based on 2009 Dwg: 17,168

TABLE 3-1 (CONTINUED): ENDICOTT REGULATED STATIONARY OIL STORAGE TANK DATA (TANKS GREATER THAN 10,000 GALLONS)

LOCATION SKID TANK EQUIPMENT ID	PRODUCT TYPE ELEVATED OR ON GRADE NOMINAL DESIGN CAPACITY (GALLONS)	FABRICATION/ INSTALLATION DATE CONSTRUCTION STANDARD	INFLOW CONTROL VALVE	OVERFILL PROTECTION DEVICE*	LEAK DETECTION SYSTEMS AND PROCEDURES	CORROSION PROTECTION	CIC TANK INTEGRITY INSPECTION (API 653) LAST NEXT INSPECTION	TANK SECONDARY CONTAINMENT CAPACITY (GALLONS)	TANK TRUCK LOADING/PERMANENT UNLOADING AREA SECONDARY CONTAINMENT CAPACITY (GALLONS)
Endicott MPI 606 T-E3-3301	(b) (7)(F) [redacted]	1986 ASME VIII, Div. 1 Shop-fabricated	(b) (7)(F) [redacted]	[redacted]	[redacted]	None	Internal: 2007 (External in lieu of internal); 2017 External: 2012; 2017	Gravel berm with CPER liner Based on 2009 Dwg: 63,420	Truck area containment - Gravel dike with spray-on polyurea liner Overflow Containment - Gravel dike with CPER liner Based on 2009 Dwg: 67,056 gallons (truck area provides 3,636 gallons; Overflow containment provides 63,420 gallons)
Endicott MPI 606 T-E3-3302	[redacted]	1985 API 650 7th Ed. APP F Shop-fabricated	[redacted]	[redacted]	[redacted]	None	Internal: 2007; 2017 External: 2012; 2017	Gravel berm with CPER liner Based on 2009 Dwg: 63,420	Truck area containment - Gravel dike with spray-on polyurea liner Overflow Containment - Gravel dike with CPER liner Based on 2009 Dwg: 67,056 gallons (truck area provides 3,636 gallons; Overflow containment provides 63,420 gallons)
Endicott SDI Pad (Mud Tank Farm) T-0001***	[redacted]	2009 API 650 Modified Shop-fabricated	[redacted]	[redacted]	[redacted]	Epoxy coating	Internal: Not applicable External: Not applicable		
Endicott SDI Pad (Mud Tank Farm) T-0002***	[redacted]	2009 API 650 modified Shop-fabricated	[redacted]	[redacted]	[redacted]	Epoxy coating	Internal: Not applicable External: Not applicable	Precast concrete walls and rig mat floor with geomembrane liner Based on 2009 Dwg: 81,395	Concrete barrier walls and gravel floor with geomembrane liner Based on 2009 Dwg: 23,429
Endicott SDI Pad (Mud Tank Farm) T-0003***	[redacted]	2009 API 650 modified Shop-fabricated	[redacted]	[redacted]	[redacted]	Epoxy coating	Internal: Not applicable External: Not applicable		

TABLE 3-1 (CONTINUED): ENDICOTT REGULATED STATIONARY OIL STORAGE TANK DATA (TANKS GREATER THAN 10,000 GALLONS)

LOCATION SKID TANK EQUIPMENT ID	PRODUCT TYPE ELEVATED OR ON GRADE NOMINAL DESIGN CAPACITY (GALLONS)	FABRICATION/ INSTALLATION DATE CONSTRUCTION STANDARD	INFLOW CONTROL VALVE	OVERFILL PROTECTION DEVICE*	LEAK DETECTION SYSTEMS AND PROCEDURES	CORROSION PROTECTION	CIC TANK INTEGRITY INSPECTION (API 653) LAST NEXT INSPECTION	TANK SECONDARY CONTAINMENT CAPACITY (GALLONS)	TANK TRUCK LOADING/PERMANENT UNLOADING AREA SECONDARY CONTAINMENT CAPACITY (GALLONS)
Endicott SDI Pad (Mud Tank Farm) T-0004***	(b) (7) (F) [redacted]	2009 API 650 modified Shop-fabricated	(b) (7)(F) [redacted]	[redacted]	[redacted]	Epoxy coating	Internal: Not applicable External: Not applicable		
Endicott SDI Pad (Mud Tank Farm) T-0005***	[redacted]	2009 API 650 modified Shop-fabricated	[redacted]	[redacted]	[redacted]	Epoxy coating	Internal: Not applicable External: Not applicable	Precast concrete walls and rig mat floor with geomembrane liner Based on 2009 Dwg: 81,395	Concrete barrier walls and gravel floor with geomembrane liner Based on 2009 Dwg: 23,429
Endicott SDI Pad (Mud Tank Farm) T-0006***	[redacted]	2009 API 650 modified Shop-fabricated	[redacted]	[redacted]	[redacted]	Epoxy coating	Internal: Not applicable External: Not applicable		

Acronyms
API – American P [redacted] tute
ASME – America [redacted] echanical Engineers
CIC – Corrosion, I [redacted] Chemicals
CPER – Chlorinat [redacted] ne
HLA – High liquid [redacted]
MPI – Main Produ [redacted]
N/A – Not applica [redacted]
SDI – Satellite Dri [redacted]

[redacted] monthly or before each transfer, whichever is less frequent.
[redacted] T-E3-1801 and T-ES-1802 are inspected monthly and tested annually.
[redacted] t to 18 AAC 75.066, .075, or Article 4.

3.1.4 GENERAL DESCRIPTION OF OIL PIPELINES AND PROCESSING FACILITIES [18 AAC 75.425(e)(3)(A)(vii)]

ENDICOTT PROCESSING FACILITIES

Endicott has one process facility with a design capacity of approximately (b) (7)(F) [redacted], 46,000 barrels of water, and 340 million standard cubic feet (mmscf) of gas daily. The process facility processes reservoir fluids from both the SDI and the MPI. The produced fluids consist of crude oil with American Petroleum Institute (API) gravity 24°, hydrocarbon gas mainly consisting of 80 percent methane, and produced water which is slightly brackish.

Produced fluids entering the process facility are treated to remove gas and water by three stages of separation. The first stage removes the majority of the produced gas and water. Two 3-phase separators, operating in series, separate the oil, gas, and water streams. Oil is dehydrated and piped to the sales oil line. Separated gas is dehydrated and compressed for on-site fuel gas requirements, artificial lift needs, and future sales. Natural gas not used for fuel or artificial lift is further compressed and re-injected into the reservoir. Levels and pressures in each separator are regulated by pneumatic and computer controls.

Water removed from the production separation process is routed to a processing module containing oily-water separation vessels, water filters, a water-disposal surge tank, and produced-water pumps. The treated water is pumped to the water flood injection wells and island disposal wells. The wastewater tank in the process facility facilitates the handling of large volumes of produced water during plant upsets, and the tank serves as a collection point for various sumps in the facility.

ENDICOTT WELLS

Endicott has approximately 70 wells on the MPI and 50 wells on the SDI. The wells are spaced on 10-foot centers in two rows approximately 170 feet apart. The production and injection wells are directionally drilled to a true vertical depth of approximately 10,000 feet.

None of the wells at Endicott require lift through the use of subsurface pumps.

ENDICOTT PIPELINES

A crude oil transmission pipeline transports sales oil from the process facility overland to Pump Station 1. The line is raised approximately 30 feet at the MPI and 5 feet at the Pump Station 1 interface. Supported on vertical support members (VSMs) 8 feet above the causeway and 5 feet above the tundra, the line rises approximately 8 feet on each side of the breaches before dropping down to the supports on the causeway breach bridges. The pipeline rises 9 feet onto the bridge across the Sagavanirktok River and has under-road crossings at the causeway "T" and on shore near the Big Skookum Bridge at the ice road crossing. See Table 3-2 for other pipeline details.

To improve oil recovery in the Endicott formation, a water flood system injects produced water. The high-pressure water injection pipeline extends from the MPI to the SDI on beams, 8 feet above the causeway, except at an under-road crossing at the causeway "T." The line rises approximately 30 feet at the MPI and 20 feet at the SDI design interface. The 3.4-mile, 14-inch outside diameter line is constructed of API-

5L-X65 steel with 0.562-inch wall thickness, 3-inch polyurethane insulation, and a 24-gauge galvanized steel jacket. At the road crossing, the pipeline has a 0.875-inch wall thickness. Expansion loops approximately 45 feet by 45 feet are installed 2,400 feet apart between the anchors.

TABLE 3-2: SUMMARY OF ENDICOTT OIL PIPELINES

FEATURE	PRODUCING WELL LINES (FACILITY OIL PIPING)[1]	PRODUCED FLUIDS (3-PHASE) FLOW LINE	CRUDE OIL TRANSMISSION PIPELINE
Length	Varies	SDI to MPI 3.5 miles; from well area to process facility on MPI.	26.5 miles
Diameter	4 inches	28 inches	16 inches
Content	Produced fluid (oil, water, gas)	Produced fluid (oil, water, gas)	Sales oil
Design	0.237-inch thick (schedule 40) duplex stainless steel 2205	0.281-inch thick duplex stainless steel with 3-inch polyurethane insulation and a 24 gauge galvanized steel jacket. Expansion loops (45'x45') every ~2,400 feet.	0.312-inch thick API-5L-X65 steel supported on beams 8 feet above the causeway and 5 feet above the tundra. Expansion loops (45'x45') every ~2,400 feet except in eastern GPB (170'x170') every ~1,600 feet.
(b) (7)(F) [redacted]			
Routing	Wells to header line	SDI header line travels from SDI to MPI process facility 8 feet above causeway and crosses under causeway. MPI header line travels aboveground from wells to process facility.	MPI process facility overland to PS1, with 2 underground road crossings, 1 at SDI road intersection and 1 under ice road near shore.
Access	Aboveground	Along causeway, aboveground at the main road tie-in.	Along causeway, aboveground.

[1] Manifold buildings are considered to be an interconnection if the buildings provide weather protection to the piping, include monitors and alarms for detecting abnormal conditions, and have floors, sills or other components that would contain most oil spills originating from piping within the building. As such, piping within manifold buildings that meet these criteria will not be considered facility oil piping under 18 AAC 75.080.

SSSV - subsurface safety valve

BADAMI CRUDE OIL TRANSMISSION PIPELINE

The 12-inch Badami crude oil transmission pipeline is 25 miles long and constructed aboveground on pile supports and is insulated with 2-inch closed cell foam. At two minor river crossings (No Name River, and part of the flood plain of the Shaviovik River), the pipe is supported on larger diameter and heavier pile sections designed to resist the anticipated ice forces at spring break-up. The pipeline is cased at three major river crossings (Sagavanirktok, Shaviovik, and Kadleroshilik rivers). The cased sections are approximately 3,200 feet in length for the Sagavanirktok River, 950 feet in length for the Shaviovik River, and 1,070 feet in length for the Kadleroshilik River. They represent 3.6 percent of the entire 25-mile route. Approximate daily throughput for the Badami crude oil transmission pipeline is between 1,000 – 1,500 barrels of oil per day.

(b) (7)(F) [redacted] to minimize potential release volumes in the event of a rupture. (b) (7)(F) [redacted]

Pipeline details are summarized below.

Design	0.281-inch thick API-5LX65 aboveground and 0.500-inch thick API-5LX65 cased steel pipe at the three river crossings.
(b) (7)(F) [redacted]	
Routing	Process facility overland to tie-in with Endicott Pipeline, with three underground river crossings.
Access	Via Rolligon or helicopter

3.1.5 FACILITY DIAGRAMS [18 AAC 75.425(E)(1)(H)]

See facility diagrams in Appendix B.

Figure B-1: Endicott Area Map

Figure B-2: MPI Location Map

Figure B-3: SDI Location Map

Figure B-4: Endicott Area Pipeline Schematic

Figure B-5: Badami Crude Oil Transmission Pipeline Location Map

PART 4. BEST AVAILABLE TECHNOLOGY [18 AAC 75.425(e)(4)]

See Volume 1 for the following sections:

4.1 Communications [18 AAC 75.425(e)(4)(A)(i)]

4.2 Source Control [18 AAC 75.425(e)(4)(A)(i)]

4.3 Trajectory Analyses and Forecasts [18 AAC 75.425(e)(4)(A)(i)]

4.4 Wildlife Capture, Treatment, and Release Programs [18 AAC 75.425(e)(4)(A)(i)]

4.5 CATHODIC PROTECTION FOR FIELD-CONSTRUCTED OIL STORAGE TANKS [18 AAC 75.425(e)(4)(A)(ii)]

Field-constructed oil storage tanks are not present at Endicott or the Badami pipeline facilities.

4.6 LEAK DETECTION SYSTEM FOR FIELD-CONSTRUCTED OIL STORAGE TANKS [18 AAC 75.425(e)(4)(A)(ii)]

Field-constructed oil storage tanks are not present at Endicott or the Badami pipeline facilities.

4.7 LIQUID LEVEL DETERMINATION FOR OIL STORAGE TANKS [18 AAC 75.425(e)(4)(A)(ii)]

(b) (7)(F)

[redacted]

TABLE 4-4: BEST AVAILABLE TECHNOLOGY ANALYSIS, STATIONARY STORAGE TANK LIQUID LEVEL DETERMINATION

BAT EVALUATION CRITERIA	(b) (7)(F) [redacted]	EXISTING METHOD: VISUAL OBSERVATION	ALTERNATE METHOD: HIGH LEVEL ALARM WITH MANUAL VALVE CLOSURE	ALTERNATE METHOD: FLOAT GAUGE	ALTERNATE METHOD: ELECTRO-MAGNETIC GAUGING	ALTERNATE METHOD: MECHANICAL SHUT-OFF VALVE
AVAILABILITY: Whether technology is best in use in other similar situations or is available for use by applicant	[redacted]	Existing method	Tanks are provided with a local level indication and a high level aud ble alarm. Operator is required to remain at fill station during operation.	Readily available. Instrument operates on the float principle.	Available. Non-contact level gauging using electromagnetic (radar) gauging.	A single action shut-off valve that stops product flow when tank level liquid rises to pre-determined capacity. Readily available.
TRANSFERABILITY: Whether each technology is transferable to applicant's operations	[redacted]	Transferable	Method is transferable.	Method is transferable and is currently in use on some tanks in the state.	Method is transferable.	Method is transferable.
EFFECTIVENESS: Whether there is a reasonable expectation each technology will provide increased spill prevention or other environmental benefits	[redacted]	Highly effective with strict adherence to Best Management Practices and local procedure. Tank liquid levels will be determined from direct observation through the hatch using a flashlight, fuel strapping tape, etc.	Operators are required to remain at or near the tank during the fill operation.	Good measurement accuracy. Readout location for gauges can vary. Can be set up to read at the tank or remotely in the control room.	Good measurement accuracy (1/100 of a foot).	Provides ability to control tank capacity. Simple design minimizes potential for malfunction. There have been some unsubstantiated reports of these valves failing in cold temperatures.
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	[redacted]	Not applicable	This system relies on the presence of an operator and as such has higher labor costs.	Undefined.	Rough order of magnitude (ROM) $75,000 per tank.	ROM $15,000 per tank.
AGE AND CONDITION: The age and condition of technology in use by the applicant	[redacted]	Procedures have been in place since 1993 for fuel transfer operations.	Method is current	Method is current.	Method is current.	Method is current.

TABLE 4-4 (CONTINUED): BEST AVAILABLE TECHNOLOGY ANALYSIS, STATIONARY STORAGE TANK LIQUID LEVEL DETERMINATION

BAT EVALUATION CRITERIA	(b) (7)(F) [redacted]	EXISTING METHOD: VISUAL OBSERVATION	ALTERNATE METHOD: HIGH LEVEL ALARM WITH MANUAL VALVE CLOSURE	ALTERNATE METHOD: FLOAT GAUGE	ALTERNATE METHOD: ELECTRO-MAGNETIC GAUGING	ALTERNATE METHOD: MECHANICAL SHUT-OFF VALVE
COMPATIBILITY: Whether each technology is compat ble with existing operations and technologies in use by the applicant	[redacted]	Compatible and widely used. Requires no change.	Method is compatible.	Method is compatible.	Method is compatible.	Compatible. Requires minimal modifications to tanks.
FEASIBILITY: The practical feas bility of each technology in terms of engineering and other operational aspects	[redacted]	Feasible and preferred due to potential for electronic or pneumatic systems to experience damage from rough handling.	Method is compatible.	ADEC has expressed concern over the use of float devices due to several failures within the State of Alaska.	Tanks and control systems could be modified to accept this technology.	Feasible.
ENVIRONMENTAL IMPACTS: Whether other environmental impacts of each technology, such as air, land, water pollution, and energy requirements, offset expected environmental benefits	[redacted]	None	There are no offsetting environmental impacts.	There are no offsetting environmental impacts.	There are no offsetting environmental impacts.	There are no offsetting environmental impacts.

Table 4-5 presents Best Available Technology (BAT) analysis for liquid level determination for ADEC-regulated portable storage tanks. 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:

Portable, temporary tanks located on gravel pads, or on rigs, are subject to vibrations and jolts. Experience shows that use of the devices on portable and temporary tanks results in error in liquid level measurement and frequent false alarms in high level and leak detection contexts. Handling during loading, transportation, and unloading may result in physical damage to the level determination device or electronic components contained therein (as applicable). Float type devices are particularly prone to "jamming" 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.

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.

The multiphase nature of fluids adversely impacts the accuracy and reliability displayed by a variety of level determination devices. Flow test tank fluids are typically composed of oil, water, associated emulsions and suspended solids. Microwave frequency device accuracy is compromised by variations in liquid dielectric constant and electrical conductivity; accordingly, application in multi-phase liquid contexts is contraindicated. 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.

Float-type 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 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.

Manufacturers of electronic devices indicate that temperatures lower than -30 degrees Fahrenheit (°F) compromise the reliability and response time of the electronic components of the devices. Weather data for North Slope locations indicate that extreme low temperatures range from -58°F to -85°F (Zang, Osterkamp, and Stamnes, 1996). Applications that are subject to these temperatures will not be warranted by the manufacturer.

The application of additional liquid level determination devices to portable and temporary tanks in remote Arctic environments is not desirable for reasons as follows:

- 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; and
- Significant cost (e.g., device, power, installation, maintenance, and replacement).

Two persons are involved in controlling the liquid level in an ADEC-regulated portable tank not equipped with a fixed level determination device while the tank is receiving oily liquids. One person operates the pump. The other person visually monitors the liquid level to prevent overfilling. The method is the best means of immediately determining the liquid level of ADEC-regulated portable bulk storage tanks as specified in 18 AAC 75.065(g)(1)(C) and (D).

TABLE 4-5: BEST AVAILABLE TECHNOLOGY ANALYSIS, PORTABLE STORAGE TANK LIQUID LEVEL DETERMINATION SYSTEM

BAT EVALUATION CRITERIA	(b) (7)(F) [redacted]	ALTERNATE METHOD: MICROPROCESSOR-BASED ELECTRONIC CONTROL SYSTEM	ALTERNATE METHOD: HARD-WIRED RELAY LOGIC CONTROL SYSTEM	ALTERNATE METHOD: PNEUMATIC CONTROL SYSTEM
AVAILABILITY: Whether technology is best in use in other similar situations or is available for use by applicant	[redacted]	Microprocessor-based PLCs are used in almost all electronic control systems in industry today.	Hardwired relay logic control systems are still in use today but are becoming less popular.	Pneumatic control systems are used in very few applications today and never where pumps and motors are turned on or off.
TRANSFERABILITY: Whether each technology is transferable to applicant's operations	[redacted]	Allen Bradley SLC5 PLCs and all instrumentation are not transferable to the drill rigs.	Undetermined	Undetermined
EFFECTIVENESS: Whether there is a reasonable expectation each technology will provide increased spill prevention or other environmental benefits	[redacted]	Not effective in this application.	Not effective in this application. In addition, relay systems do not provide for logic status monitoring or alarming.	Not effective in this application. In addition, pneumatic systems are prone to freezing if moisture build-up occurs in the tubing.
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.	[redacted]	The cost to redesign the rig and its associated storage tank would be high.	The cost of design changes to a relay based logic system is high. Re-wiring is required for any revision.	The cost of design changes to a pneumatic logic system is high. Re-tubing is required for any revision.
AGE AND CONDITION: The age and condition of technology in use by the applicant	[redacted]	Not applicable	Not applicable	Not applicable

TABLE 4-5 (CONTINUED): BEST AVAILABLE TECHNOLOGY ANALYSIS, PORTABLE STORAGE TANK LIQUID LEVEL DETERMINATION SYSTEM

BAT EVALUATION CRITERIA	(b) (7)(F) [redacted]	ALTERNATE METHOD: MICROPROCESSOR-BASED ELECTRONIC CONTROL SYSTEM	ALTERNATE METHOD: HARD-WIRED RELAY LOGIC CONTROL SYSTEM	ALTERNATE METHOD: PNEUMATIC CONTROL SYSTEM
COMPATIBILITY: Whether each technology is compatible with existing operations and technologies in use by the applicant	[redacted]	Compat ble but not used on portable tanks and tanks on rigs.	Compatible but not used on portable tanks and tanks on rigs.	Compatible but not used on portable tanks and tanks on rigs.
FEASIBILITY: The practical feasibility of each technology in terms of engineering and other operational aspects	[redacted]	Rig tanks are frequently moved over rough roads. Rough handling has the potential to affect the accuracy and/or operability of the system.	Rig tanks are frequently moved over rough roads. Rough handling has the potential to affect the accuracy and/or operability of the system.	Rig tanks are frequently moved over rough roads. Rough handling has the potential to affect the accuracy and/or operability of the system.
ENVIRONMENTAL IMPACTS: Whether other environmental impacts of each technology, such as air, land, water pollution, and energy requirements offset any anticipated environmental benefits	[redacted]	None	None	None

4.8 MAINTENANCE PRACTICES FOR BURIED METALLIC FACILITY OIL PIPING – PROTECTIVE COATING AND CATHODIC PROTECTION [18 AAC 75.425(e)(4)(A)(ii)]

Because protective coating and cathodic protection are not required on buried facility oil piping installed before 1992, a BAT analysis is not necessary. Endicott's buried facility oil piping was installed before 1992 and consequently is not subject to 18 AAC 75.080(d).

4.9 MAINTENANCE PRACTICES FOR BURIED FACILITY OIL PIPING – CORROSION SURVEYS [18 AAC 75.425(e)(4)(A)(ii)]

The 2-inch gasoline and diesel lines servicing the Endicott retail fuel area are cathodically protected facility oil piping buried directly in soil. Cathodic protection (CP) surveys are conducted on these lines, as required by 18 AAC 75.080(k)(2). The CP testing is in strict compliance with National Association of Corrosion Engineers (NACE) SP 0169 and performed by a qualified CP tester, as required by 18 AAC 75.080(k). The piping is less than 100 feet long, and as such test stations are not needed.

4.10 LEAK DETECTION FOR CRUDE OIL TRANSMISSION PIPELINE [18 AAC 75.425(e)(4)(A)(iv)]

(b) (7)(F)

[redacted]

TABLE 4-6: BEST AVAILABLE TECHNOLOGY ANALYSIS, LEAK DETECTION IN CRUDE OIL PIPELINE

BAT EVALUATION CRITERIA	(b) (7)(F) [redacted]	VISUAL SURVEILLANCE	PRESSURE POINT ANALYSIS (NO LONGER IN USE)	LINE VOLUME BALANCE SYSTEM	TRANSIENT VOLUME BALANCE SYSTEM
AVAILABILITY: Whether technology is best in use in other similar situations or is available for use by applicant	[redacted]	Technology is available, but dated.	Technology has been used on other operating pipelines.	Technology is available and is commonly used on operating pipelines. It takes measured volumes in and out of the pipeline system and compares these to determine if there is a leak.	Technology is available and is used for operating pipelines. A model takes real data from the pipeline and compares actual results against those computed by model. If they do not compare there is an alarm
TRANSFERABILITY: Whether each technology is transferable to applicant's operations	[redacted]	Can be used.	PPA is used widely on crude oil pipelines. This technology performs best if: Transient flow conditions do not occur frequently. There is no multi-phase flow. There is no slack line flow.	Can be used.	Can be used.
EFFECTIVENESS: Whether there is a reasonable expectation each technology will provide increased spill prevention or other environmental benefits	[redacted]	An effective means of identifying a leak that can be visually detected. Sometimes leaks occur that are below the threshold limit of the leak detection system and are spotted by visual detection.	It is unlikely that 1% sensitivity can be achieved through PPA, although the system still does have merit, even with less sensitive capabilities. EFA claims PPA and Leak Locator can detect leaks that are as low as or less than 1% of daily throughput. However, PPA and Leak Locator system performance are dependent upon stable flow without hydraulic "noise" and do not provide effective leak detection for the pipeline.	Effectiveness is reduced if pipeline is networked.	A transient model can be effective if field data is accurate, timely, and consistent. The effectiveness of the system suffers when there are changes in the operations or inconsistent data.

TABLE 4-6 (CONTINUED): BEST AVAILABLE TECHNOLOGY ANALYSIS, LEAK DETECTION IN CRUDE OIL PIPELINE

BAT EVALUATION CRITERIA	(b) (7)(F) [redacted]	VISUAL SURVEILLANCE	PRESSURE POINT ANALYSIS (NO LONGER IN USE)	LINE VOLUME BALANCE SYSTEM	TRANSIENT VOLUME BALANCE SYSTEM
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		The cost would be based on trips to cover the pipeline right-of-way. No up-front investment.	The system has been purchased and installed.	Approximate cost is $100,000.	Approximate cost is $200,000.
AGE AND CONDITION: The age and condition of technology in use by the applicant		Method is current.	The system was relatively new when purchased and methods are current	Method is current.	Method is current.
COMPATIBILITY: Whether each technology is compatible with existing operations and technologies in use by the applicant		Compatible but small leaks in the below grade sections might go undetected.	PPA and Leak Locator are less compat ble with the pipeline design and process operations. PPA is less compatible with the facility design and process operations.	Compatible with the computer and communications systems proposed for the pipeline system. Would require significant work if additional segments added.	There may be compatibility problems with the computer systems proposed for the pipeline system because a model would have to run continuously.
FEASIBILITY: The practical feasibility of each technology in terms of engineering and other operational aspects		Not feasible to continuously monitor the entire pipeline. Is useful as supplement to an online leak detection system.	PPA is state-of-the-art, proven technology that is ideally suited to steady-state flow conditions. Its sensitivity to pipelines with transient flow conditions is somewhat diminished for Endicott.	Method is feasible and commonly used.	Method is feas ble but does provide some risk because of the need to run a model and maintain a model.

TABLE 4-6 (CONTINUED): BEST AVAILABLE TECHNOLOGY ANALYSIS, LEAK DETECTION IN CRUDE OIL PIPELINE

BAT EVALUATION CRITERIA	(b) (7)(F) [redacted]	VISUAL SURVEILLANCE	PRESSURE POINT ANALYSIS (NO LONGER IN USE)	LINE VOLUME BALANCE SYSTEM	TRANSIENT VOLUME BALANCE SYSTEM
ENVIRONMENTAL IMPACTS: Whether other environmental impacts of each technology, such as air, land, water pollution, and energy requirements, offset any anticipated environmental benefits	[redacted]	Depending on the mode of transportation it could have affects on the tundra.	No additional environmental impacts.	No impact.	No impact.

PART 5. RESPONSE PLANNING STANDARD [18 AAC 75.425(e)(5)]

Part 5, Response Planning Standard, is in Volume 1.

APPENDIX A

PORTABLE SHOP-FABRICATED TANK TABLE

APPENDIX A: ADEC-REGULATED PORTABLE, SHOP-FABRICATED STORAGE TANK DATA
TANKS GREATER THAN 10,000 GALLONS ON BPXA LEASES

Tank Number	Typical Location	Description	Fabrication Date	(b) (7)(F) [redacted]	Product Type	Secondary Containment Description	Internal Inspection Last; Next	External Inspection Last; Next	(b) (7)(F) [redacted]	Liquid Level Mechanism/Overfill Protection	(b) (7)(F) [redacted]	Corrosion Protection	Comments
108	END	Double-walled	1983	[redacted]	Miscellaneous hydrocarbons and water	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2010; 2015	2010; 2015	[redacted]	Visual observation	[redacted]	Internal Lining	TANKCO
111	GPB	Rectangular on Skid	1983	[redacted]	Miscellaneous hydrocarbons and water	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2010; 2015	2010; 2015	[redacted]	Visual observation	[redacted]	None	TANKCO
114	GPB	Horizontal, rectangular double wall	1983	[redacted]	Hydrocarbons	Double wall[1]	2010; 2015	2010; 2015	[redacted]	Visual observation	[redacted]	Internal Lining	TANKCO
115	GPB	Horizontal, double wall	1983	[redacted]	Miscellaneous hydrocarbons and water	Double wall[1]	2010; 2015	2010; 2015	[redacted]	Visual observation	[redacted]	Internal Lining	TANKCO
116	GPB	Horizontal, double wall	1983	[redacted]	Hydrocarbons	Double wall[1]	2010; 2015	2010; 2015	[redacted]	Visual observation	[redacted]	Internal Lining	TANKCO
117	GPB	Horizontal, double wall	1983	[redacted]	Hydrocarbons	Double wall[1]	2010; 2015	2010; 2015	[redacted]	Visual observation	[redacted]	Internal Lining	TANKCO
118	GPB	Horizontal, double wall	1983	[redacted]	Hydrocarbons	Double wall[1]	2010; 2015	2010; 2015	[redacted]	Visual observation	[redacted]	Internal Lining	TANKCO
119	GPB	Horizontal, double wall	1983	[redacted]	Hydrocarbons	Double wall[1]	2010; 2015	2010; 2015	[redacted]	Visual observation	[redacted]	Internal Lining	TANKCO
121	GPB	Horizontal, rectangular double wall	1983	[redacted]	Hydrocarbons	Double wall[1]	2010; 2015	2010; 2015	[redacted]	Visual observation	[redacted]	Internal Lining	TANKCO
122	GPB	Horizontal, rectangular double wall	1983	[redacted]	Hydrocarbons	Double wall[1]	2010; 2013	2010; 2013	[redacted]	Visual observation	[redacted]	Internal Lining	TANKCO
123	GPB	Horizontal, rectangular double wall	1983	[redacted]	Hydrocarbons	Double wall[1]	2010; 2015	2010; 2015	[redacted]	Visual observation	[redacted]	Internal Lining	TANKCO
124	GPB	Horizontal, rectangular double wall	1983	[redacted]	Hydrocarbons	Double wall[1]	2010; 2015	2010; 2015	[redacted]	Visual observation	[redacted]	Internal Lining	TANKCO
125	GPB	Rectangular on Skid	1983	[redacted]	Miscellaneous Hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2010; 2015	2010; 2015	[redacted]	Visual observation	[redacted]	None	TANKCO
127	GPB / Skid 50	Horizontal, rectangular double wall	1983	[redacted]	Hydrocarbons	Double wall[1]	2010; 2015	2010; 2015	[redacted]	Visual observation	[redacted]	Internal Lining	TANKCO
128	GPB	Horizontal, rectangular double wall	1983	[redacted]	Hydrocarbons	Double wall[1]	2010; 2015	2010; 2015	[redacted]	Visual observation	[redacted]	None	TANKCO
130	MPU	Double-wall, welded steel; Herc	1983	[redacted]	Miscellaneous hydrocarbons	Double wall[1]	2010; 2015	2010; 2015	[redacted]	Visual observation	[redacted]	Internal Lining	TANKCO
131	GPB	Horizontal, double wall	1983	[redacted]	Hydrocarbons	Double wall[1]	2010; 2015	2010; 2015	[redacted]	Visual observation	[redacted]	None	TANKCO

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Tank Number	Typical Location	Description	Fabrication Date	(b) (7)(F) [redacted]	Product Type	Secondary Containment Description	Internal Inspection Last; Next	External Inspection Last; Next	(b) (7)(F) [redacted]	Liquid Level Mechanism/Overfill Protection	(b) (7)(F) [redacted]	Corrosion Protection	Comments
132	GPB	Horizontal, rectangular double wall	1983	[redacted]	Hydrocarbons	Double wall[1]	2010; 2015	2010; 2015	[redacted]	Visual observation	[redacted]	None	TANKCO
01-09	GPB	Single wall, skid-mounted upright	2001	[redacted]	Hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2010; 2015	2010; 2015	[redacted]	Visual observation	[redacted]	None	ASRC
01-10	GPB	Single wall, skid-mounted upright	2001	[redacted]	Hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2010; 2015	2010; 2015	[redacted]	Visual observation	[redacted]	None	ASRC
01-11	GPB	Single wall, skid-mounted upright	2001	[redacted]	Hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2010; 2015	2010; 2015	[redacted]	Visual observation	[redacted]	None	ASRC
01-12	GPB	Single wall, skid-mounted upright	2001	[redacted]	Hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2010; 2015	2010; 2015	[redacted]	Visual observation	[redacted]	None	ASRC
01-13	GPB	Single wall, skid-mounted upright	2001	[redacted]	Hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2010; 2015	2010; 2015	[redacted]	Visual observation	[redacted]	None	ASRC
01-14	GPB	Single wall, skid-mounted upright	2001	[redacted]	Hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2010; 2015	2010; 2015	[redacted]	Visual observation	[redacted]	None	ASRC
73020	GPB	Tiger Tank	2000	[redacted]	Miscellaneous Hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2011; 2016	2011; 2016	[redacted]	Visual observation	[redacted]	None	CH2M Hill
73021	GPB	Tiger Tank	2000	[redacted]	Miscellaneous Hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2011; 2016	2011; 2016	[redacted]	Visual observation	[redacted]	None	CH2M Hill
73022	GPB	Tiger Tank	2000	[redacted]	Miscellaneous Hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2010; 2015	2010; 2015	[redacted]	Visual observation	[redacted]	None	CH2M Hill

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TANKS GREATER THAN 10,000 GALLONS ON BPXA LEASES

Tank Number	Typical Location	Description	Fabrication Date	(b) (7)(F) [redacted]	Product Type	Secondary Containment Description	Internal Inspection Last; Next	External Inspection Last; Next	(b) (7)(F) [redacted]	Liquid Level Mechanism/Overfill Protection	(b) (7)(F) [redacted]	Corrosion Protection	Comments
73023	GPB	Tiger Tank	2000	[redacted]	Miscellaneous Hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2011; 2016	2011; 2016	[redacted]	Visual observation	[redacted]	None	CH2M Hill
73024	GPB	Tiger Tank	2000	[redacted]	Miscellaneous Hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2010; 2015	2010; 2015	[redacted]	Visual observation	[redacted]	None	CH2M Hill
73043	GPB	Open top	1988	[redacted]	Miscellaneous Hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2012; 2017	2012; 2017	[redacted]	Visual observation	[redacted]	None	CH2M Hill
73047	GPB	Open top	1984	[redacted]	Miscellaneous Hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2011; 2016	2011; 2016	[redacted]	Visual observation	[redacted]	None	CH2M Hill
73052	GPB	Tiger Tank	1995	[redacted]	Miscellaneous Hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2012; 2015	2012; 2015	[redacted]	Visual observation	[redacted]	Internal Paint Coa ing	CH2M Hill
73067	GPB	Open top	2002	[redacted]	Miscellaneous Hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2011; 2016	2011; 2016	[redacted]	Visual observation	[redacted]	None	CH2M Hill
73068	GPB	Open top	2002	[redacted]	Miscellaneous Hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2011; 2016	2011; 2016	[redacted]	Visual observation	[redacted]	None	CH2M Hill
73069	GPB	Open top	2002	[redacted]	Miscellaneous Hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2011; 2016	2011; 2016	[redacted]	Visual observation	[redacted]	None	CH2M Hill
73070	GPB	Open top	2002	[redacted]	Miscellaneous Hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2010; 2015	2010; 2015	[redacted]	Visual observation	[redacted]	None	CH2M Hill
73080	GPB	Double-wall flowback Tank	2004	[redacted]	Miscellaneous Hydrocarbons	Double wall[1]	2011; 2013	2011; 2013	[redacted]	Visual observation; overfill diverted to interstitial space; catchment at truck connections	[redacted]	None	CH2M Hill

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TANKS GREATER THAN 10,000 GALLONS ON BPXA LEASES

Tank Number	Typical Location	Description	Fabrication Date	(b) (7) (F) [redacted]	Product Type	Secondary Containment Description	Internal Inspection Last; Next	External Inspection Last; Next	(b) (7)(F) [redacted]	Liquid Level Mechanism/Overfill Protection	(b) (7)(F) [redacted]	Corrosion Protection	Comments
73081	GPB	Double-wall flowback Tank	2004	[redacted]	Miscellaneous Hydrocarbons	Double wall[1]	2010; 2015	2010; 2015	[redacted]	Visual observation; overfill diverted to interstitial space; catchment at truck connections	[redacted]	None	CH2M Hill
73091	GPB / DSM	Horizontal, rectangular double wall	2006	[redacted]	Hydrocarbons	Double wall[1]	2010; 2015	2010; 2015	[redacted]	Visual observation; welded catchment at fill connections	[redacted]	Internal Lining	CH2M Hill
73092	GPB / DSM	Horizontal, rectangular double wall	2006	[redacted]	Hydrocarbons	Double wall[1]	2010; 2015	2010; 2015	[redacted]	Visual observation; welded catchment at fill connections	[redacted]	Internal Lining	CH2M Hill
73093	GPB / DSM	Horizontal, rectangular double wall	2006	[redacted]	Hydrocarbons	Double wall[1]	2012; 2017	2012; 2017	[redacted]	Visual observation; welded catchment at fill connections	[redacted]	Internal Lining	CH2M Hill
73094	GPB / DSM	Horizontal, rectangular double wall	2006	[redacted]	Hydrocarbons	Double wall[1]	2012; 2017	2012; 2017	[redacted]	Visual observation; welded catchment at fill connections	[redacted]	Galvanic Anodes and Internal Lining	CH2M Hill
73095	GPB / DSM	Horizontal, rectangular double wall	2006	[redacted]	Hydrocarbons	Double wall[1]	2012; 2017	2012; 2017	[redacted]	Visual observation; welded catchment at fill connections	[redacted]	Internal Lining	CH2M Hill
73096	GPB / DSM	Horizontal, rectangular double wall	2006	[redacted]	Hydrocarbons	Double wall[1]	2012; 2017	2012; 2017	[redacted]	Visual observation; welded catchment at fill connections	[redacted]	Galvanic Anodes and Internal Lining	CH2M Hill
73097	GPB / DSM	Horizontal, rectangular double wall	2007	[redacted]	Hydrocarbons	Double wall[1]	2010; 2015	2010; 2015	[redacted]	Visual observation; welded catchment at fill connections	[redacted]	Internal Lining	CH2M Hill
73098	GPB / DSM	Horizontal, rectangular double wall	2007	[redacted]	Hydrocarbons	Double wall[1]	2012; 2017	2012; 2017	[redacted]	Visual observation; welded catchment at fill connections	[redacted]	Galvanic Anodes and Internal Lining	CH2M Hill
73099	GPB / DSM	Horizontal, rectangular double wall	2007	[redacted]	Hydrocarbons	Double wall[1]	2010; 2015	2010; 2015	[redacted]	Visual observation; welded catchment at fill connections	[redacted]	Galvanic Anodes and Internal Lining	CH2M Hill
73100	GPB / DSM	Horizontal, rectangular double wall	2007	[redacted]	Hydrocarbons	Double wall[1]	2012; 2017	2012; 2017	[redacted]	Visual observation; welded catchment at fill connections	[redacted]	Galvanic Anodes and Internal Lining	CH2M Hill
73116	GPB / DSM	Horizontal, rectangular double wall	2007	[redacted]	Hydrocarbons	Double wall[1]	2010; 2015	2010; 2015	[redacted]	Visual observation; welded catchment at fill connections	[redacted]	Galvanic Anodes and Internal Lining	

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Tank Number	Typical Location	Description	Fabrication Date	(b) (7)(F) [redacted]	Product Type	Secondary Containment Description	Internal Inspection Last; Next	External Inspection Last; Next	(b) (7)(F) [redacted]	Liquid Level Mechanism/Overfill Protection	(b) (7)(F) [redacted]	Corrosion Protection	Comments
73117	GPB / DSM	Horizontal, rectangular double wall	2007	[redacted]	Hydrocarbons	Double wall[1]	2010; 2015	2010; 2015	[redacted]	Visual observation; welded catchment at fill connections	[redacted]	Galvanic Anodes and Internal Lining	
55-1901	Nordic 1 Rig (GPB)	Double wall, open top	2008	[redacted]	Hydrocarbons	Double wall[1]	2012; 2017	2012; 2017	[redacted]	Visual observation; fixed catchment at fill connections	[redacted]	Internal Lining	
94-459	GPB	Horizontal, rectangular double wall	2011	[redacted]	Hydrocarbons	Double wall[1]	2011; 2016	2011; 2016	[redacted]	Visual observation, welded catchment at fill connections	[redacted]	Galvanic Anodes and Internal Lining	
94-460	GPB	Horizontal, rectangular double wall	2011	[redacted]	Hydrocarbons	Double wall[1]	2011; 2016	2011; 2016	[redacted]	Visual observation, welded catchment at fill connections	[redacted]	Galvanic Anodes and Internal Lining	
94-461	GPB	Horizontal, rectangular double wall	2011	[redacted]	Hydrocarbons	Double wall[1]	2011; 2016	2011; 2016	[redacted]	Visual observation, welded catchment at fill connections	[redacted]	Galvanic Anodes and Internal Lining	
94-462	GPB	Horizontal, rectangular double wall	2011	[redacted]	Hydrocarbons	Double wall[1]	2011; 2016	2011; 2016	[redacted]	Visual observation, welded catchment at fill connections	[redacted]	Galvanic Anodes and Internal Lining	
95-94-645	GPB	Open top	1995	[redacted]	Various	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2010; 2015	2010; 2015	[redacted]	Visual observation	[redacted]	Coal Tar Lining	
H-01	MPU	Single wall, vertical, upright cylindrical tank	Unknown	[redacted]	Hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2011; 2016	2011; 2016	[redacted]	Visual observation	[redacted]	Internal Lining	TANKCO
H-02	MPU	Single wall, vertical, upright cylindrical tank	Unknown	[redacted]	Hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2011; 2016	2011; 2016	[redacted]	Visual observation	[redacted]	Internal Lining	TANKCO
H-03	MPU	Single wall, vertical, upright cylindrical tank	Unknown	[redacted]	Hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2011; 2016	2011; 2016	[redacted]	Visual observation	[redacted]	Internal Lining	TANKCO
H-04	MPU	Single wall, vertical, upright cylindrical tank	Unknown	[redacted]	Hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2011; 2016	2011; 2016	[redacted]	Visual observation	[redacted]	Internal Lining	TANKCO

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Tank Number	Typical Location	Description	Fabrication Date	(b) (7)(F) [redacted]	Product Type	Secondary Containment Description	Internal Inspection Last; Next	External Inspection Last; Next	(b) (7)(F) [redacted]	Liquid Level Mechanism/Overfill Protection	(b) (7)(F) [redacted]	Corrosion Protection	Comments
H-05	MPU	Single wall, vertical, upright cylindrical tank	Unknown	[redacted]	Hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2011; 2016	2011; 2016	[redacted]	Visual observation	[redacted]	None	TANKCO
H-06	MPU	Single wall, vertical, upright cylindrical tank	Unknown	[redacted]	Hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2011; 2016	2011; 2016	[redacted]	Visual observation	[redacted]	None	TANKCO
H-07	MPU	Single wall, vertical, upright cylindrical tank	Unknown	[redacted]	Hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2011; 2016	2011; 2016	[redacted]	Visual observation	[redacted]	Internal Lining	TANKCO
H-08	MPU	Single wall, vertical, upright cylindrical tank	Unknown	[redacted]	Hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2011; 2016	2011; 2016	[redacted]	Visual observation	[redacted]	Internal Lining	TANKCO
MPU-05	MPU	Upright cylindrical tank, skid mounted	Est. 1983	[redacted]	Miscellaneous Hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2012; 2015	2012; 2015	[redacted]	Visual observation	[redacted]	None	
MPU-06	MPU	Upright cylindrical tank, skid mounted	Est. 1983	[redacted]	Miscellaneous Hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2012; 2017	2012; 2017	[redacted]	Visual observation	[redacted]	None	
MPU-09	MPU	Open top, non-insulated	1998	[redacted]	Miscellaneous Hydrocarbons	Welded steel pan in addition to berm with impermeable liner	2011; 2016	2011; 2016	[redacted]	Visual observation	[redacted]	None	
MPU-10	MPU	Open top, non-insulated	1998	[redacted]	Miscellaneous Hydrocarbons	Welded steel pan in addition to berm with impermeable liner	2011; 2016	2011; 2016	[redacted]	Visual observation	[redacted]	None	
MPU-12	MPU	Double-wall Portable Flowback Tank	2000	[redacted]	Miscellaneous Hydrocarbons	Double wall[1]	2010; 2015	2010; 2015	[redacted]	Visual observation	[redacted]	None	
MPU-13	MPU	Double-wall Portable Flowback Tank	2002	[redacted]	Miscellaneous Hydrocarbons	Double wall[1]	2010; 2015	2010; 2015	[redacted]	Visual observation	[redacted]	None	
MPU-14	MPU	Double-wall Portable Flowback Tank	2002	[redacted]	Miscellaneous Hydrocarbons	Double wall[1]	2012; 2017	2012; 2017	[redacted]	Visual observation	[redacted]	None	
MPU-15	MPU	Double wall, rectangular, open top	2007	[redacted]	Hydrocarbons	Double wall[1]	2010; 2015	2010; 2015	[redacted]	Visual observation; fixed pans at fill connections	[redacted]	Internal Lining	Drain plug at the base of the outer wall

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TANKS GREATER THAN 10,000 GALLONS ON BPXA LEASES

Tank Number	Typical Location	Description	Fabrication Date	(b) (7) (F) [redacted]	Product Type	Secondary Containment Description	Internal Inspection Last; Next	External Inspection Last; Next	(b) (7)(F) [redacted]	Liquid Level Mechanism/Overfill Protection	(b) (7)(F) [redacted]	Corrosion Protection	Comments
MPU-16	MPU	Horizontal, rectangular double wall	2007	[redacted]	Hydrocarbons	Double wall[1]	2010; 2015	2010; 2015	[redacted]	Visual observation; fixed pans at fill connections	[redacted]	Internal Lining	Drain plug at the base of the outer wall
O-1 (Formerly CTU-01)	GPB	Horizontal, double wall	1990	[redacted]	Miscellaneous Hydrocarbons	Double wall[1]	2008; 2013	2008; 2013	[redacted]	Visual observation	[redacted]	Internal Lining	TANKCO
O-10	GPB	Open top	1995	[redacted]	Miscellaneous Hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2010; 2015	2010; 2015	[redacted]	Visual observation	[redacted]	None	TANKCO
O-11	END	Open top	1990	[redacted]	Miscellaneous Hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2010; 2015	2010; 2015	[redacted]	Visual observation	[redacted]	None	TANKCO
O-15	GPB	Single-walled; open top	Unknown	[redacted]	Miscellaneous Hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2010; 2015	2010; 2015	[redacted]	Visual observation	[redacted]	None	TANKCO
O-16	END	Single-walled; open top	Unknown	[redacted]	Miscellaneous Hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2008; 2013	2011; 2016	[redacted]	Visual observation	[redacted]	Internal Lining	TANKCO
O-18	GPB / DSM	Single wall, open top	Unknown	[redacted]	Hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2011; 2016	2011; 2016	[redacted]	Visual observation	[redacted]	Internal Lining	
O-21	GPB	Single walled; Open top	1987	[redacted]	Miscellaneous Hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2011; 2016	2011; 2016	[redacted]	Visual observation	[redacted]	Internal Lining	TANKCO
O-22	GPB	Flowback Tank	1987	[redacted]	Miscellaneous Hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2011; 2016	2011; 2016	[redacted]	Visual observation	[redacted]	Internal Lining	TANKCO
O-23	GPB	Flowback Tank	1987	[redacted]	Miscellaneous Hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2008; 2013	2008; 2013	[redacted]	Visual observation	[redacted]	Internal Lining	TANKCO
O-3 (Formerly CTU-03)	GPB	Horizontal, double wall	1990	[redacted]	Miscellaneous Hydrocarbons	Double wall[1]	2010; 2015	2011; 2016	[redacted]	Visual observation	[redacted]	Internal Lining	TANKCO

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Tank Number	Typical Location	Description	Fabrication Date	(b) (7)(F) [redacted]	Product Type	Secondary Containment Description	Internal Inspection Last; Next	External Inspection Last; Next	(b) (7)(F) [redacted]	Liquid Level Mechanism/Overfill Protection	(b) (7)(F) [redacted]	Corrosion Protection	Comments
O-5 (Formerly CTU-05)	GPB	Double-walled; open top	1983	[redacted]	Miscellaneous Hydrocarbons	Double wall[1]	2008; 2013	2008; 2013	[redacted]	Visual observation	[redacted]	Internal Lining	TANKCO
O-8 (Formerly CTU-08)	GPB	Horizontal, double wall	1992	[redacted]	Miscellaneous Hydrocarbons	Double wall[1]	2011; 2016	2011; 2016	[redacted]	Visual observation	[redacted]	Internal Lining	TANKCO
O-9 (Formerly CTU-09)	GPB	Horizontal, double wall	1992	[redacted]	Miscellaneous Hydrocarbons	Double wall[1]	2011; 2016	2011; 2016	[redacted]	Visual observation	[redacted]	Internal Lining	TANKCO
T-03-9003	GPB	Spicer Tank	1983	[redacted]	Various	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2011; 2013	2011; 2013	[redacted]	Visual observation	[redacted]	None	
T-1123	MPU	Upright, portable, single wall, skid-mounted	2008	[redacted]	Hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2012; 2017	2012; 2017	[redacted]	Visual observation	[redacted]	Internal Lining	
T-1124	MPU	Upright, portable, single wall, skid-mounted	2008	[redacted]	Hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2012; 2017	2012; 2017	[redacted]	Visual observation	[redacted]	Internal Lining	
T-12	PS1	Horizontal, closed-top Tiger	Unknown	[redacted]	Crude Oil	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2011; 2016	2011; 2016	[redacted]	Visual observation	[redacted]	Internal Lining	Pig receiver tank at PS 1
T-14	PS1	Horizontal, rectangular Tiger	Unknown	[redacted]	Miscellaneous hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2010; 2015	2010; 2015	[redacted]	Visual observation	[redacted]	Internal Lining	TANKCO; coa ing applied September 2006
T-18	GPB, END	Horizontal rectangular; Tiger	1990	[redacted]	Miscellaneous hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2012; 2015	2012; 2015	[redacted]	Visual observation	[redacted]	Internal Lining	TANKCO
T-19	GPB, END	Horizontal rectangular; Tiger	1990	[redacted]	Miscellaneous hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2012; 2015	2012; 2015	[redacted]	Visual observation	[redacted]	Internal Lining	TANKCO
T-20	GPB	Horizontal, single wall	1990	[redacted]	Hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2009; 2015	2009; 2015	[redacted]	Visual observation	[redacted]	Internal Lining	TANKCO

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Tank Number	Typical Location	Description	Fabrication Date	(b) (7)(F) [redacted]	Product Type	Secondary Containment Description	Internal Inspection Last; Next	External Inspection Last; Next	(b) (7)(F) [redacted]	Liquid Level Mechanism/Overfill Protection	(b) (7)(F) [redacted]	Corrosion Protection	Comments
T-20451 Not in Service	END SDI	Ver ical, cylindrical, and elevated	2009	[redacted]	Drilling muds and fluids	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	Not in Service	Not in Service	b [redacted]	High-level alarm; Liquid level monitoring in CRI Unit	[redacted]	Epoxy coating	
T-20452 Not in Service	END SDI	Ver ical, cylindrical, and elevated	2009	[redacted]	Drilling muds and fluids	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	Not in Service	Not in Service	b [redacted]	High-level alarm; Liquid level monitoring in CRI Unit	[redacted]	Epoxy coating	
T-21	GPB	Horizontal, single wall	1990	[redacted]	Hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2008; 2013	2008; 2013	[redacted]	Visual observation	[redacted]	Internal Lining	TANKCO
T-4127E	Nabors Rig 27E	Horizontal, rectangular single wall	Unknown	[redacted]	Hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2012; 2013	2012; 2013	[redacted]	Visual observation	[redacted]	None	
T-419-005	GPB	Horizontal, rectangular	Unknown	[redacted]	Hydrocarbons	Double wall[1]	2009; 2014	2009; 2014	[redacted]	Visual observation	[redacted]	None	
T-8208A	MPU	Horizontal, rectangular double wall	1999	[redacted]	Hydrocarbons	Double wall[1]	2012; 2017	2012; 2017	[redacted]	Visual observation	[redacted]	None	
T-8208B	MPU	Horizontal, rectangular double wall	1999	[redacted]	Hydrocarbons	Double wall[1]	2010; 2015	2010; 2015	[redacted]	Visual observation	[redacted]	None	
T-8208C	MPU	Horizontal, rectangular double wall	1999	[redacted]	Hydrocarbons	Double wall[1]	2010; 2015	2010; 2015	[redacted]	Visual observation	[redacted]	None	

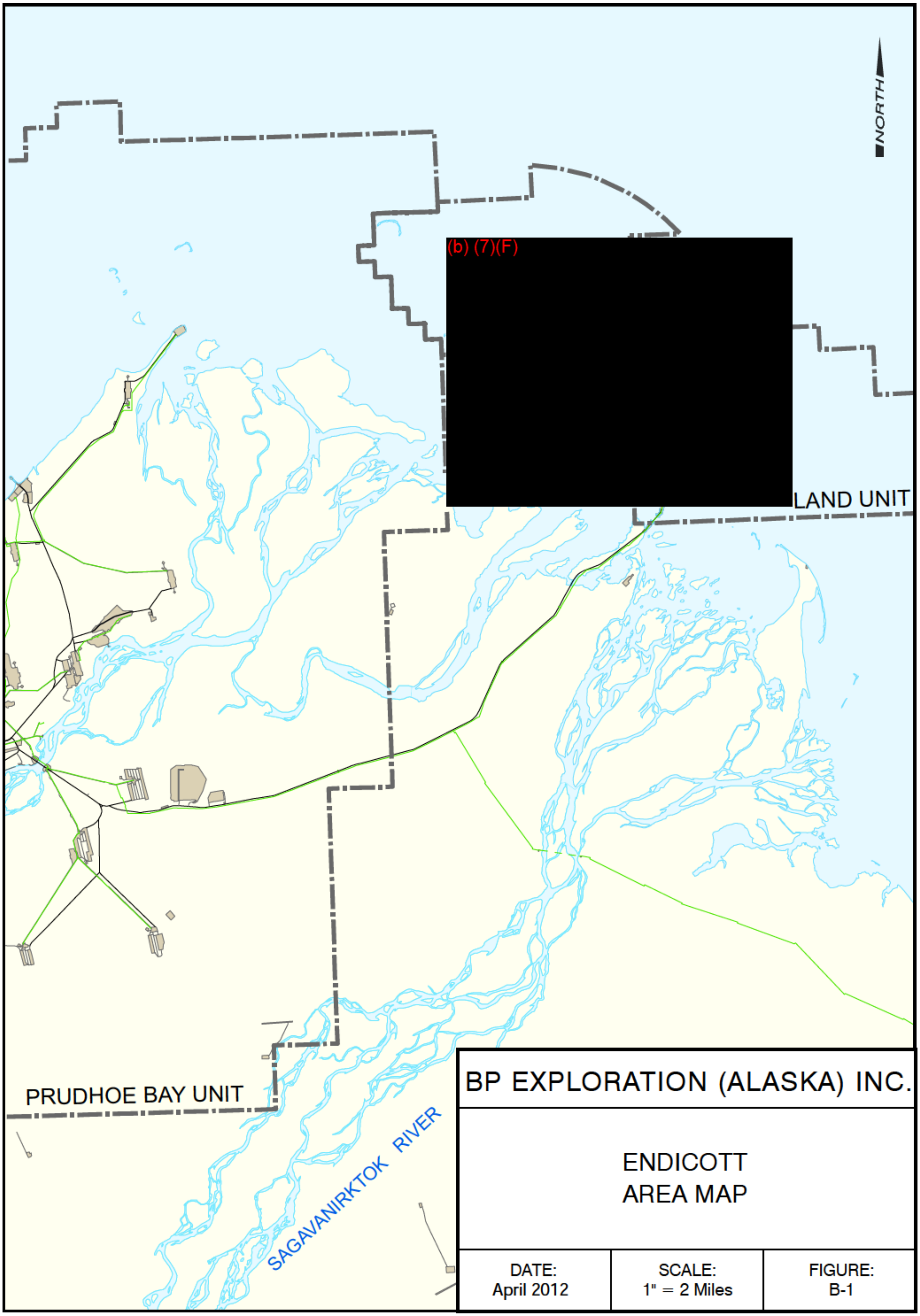
Notes:

1 - The outer wall of a double-walled aboveground oil s [redacted] onsidered secondary containment. Additional lined secondary containment is required for double-walled tanks if they are equippe [redacted] erfill containment system, a means to monitor the interstitial space (e g., view port) and a means to drain the inters i ial space, as [redacted] AAC 75.066(e).

APPENDIX B

FACILITY DIAGRAMS

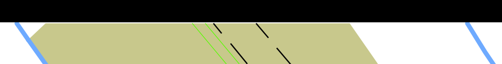
PHMSA000012498



pe13472_end.mxd

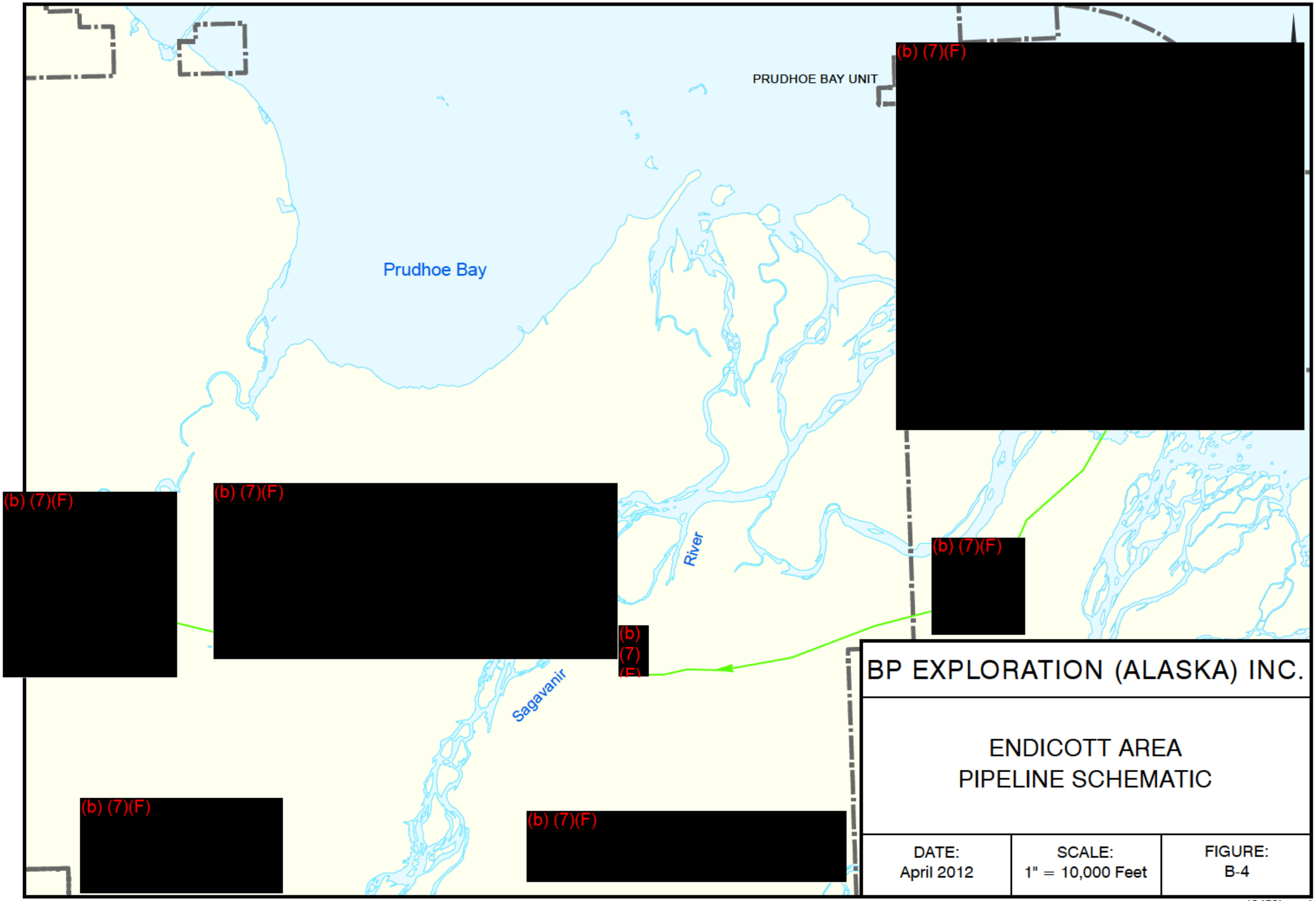
(b) (7)(F)

[redacted]



(b) (7)(F)

[redacted]


PRUDHOE BAY UNIT
Prudhoe Bay
River
Sagavanir
(b) (7)(F)
[redacted]
(b) (7)(F)
[redacted]
(b) (7)(F)
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(b) (7)(F)
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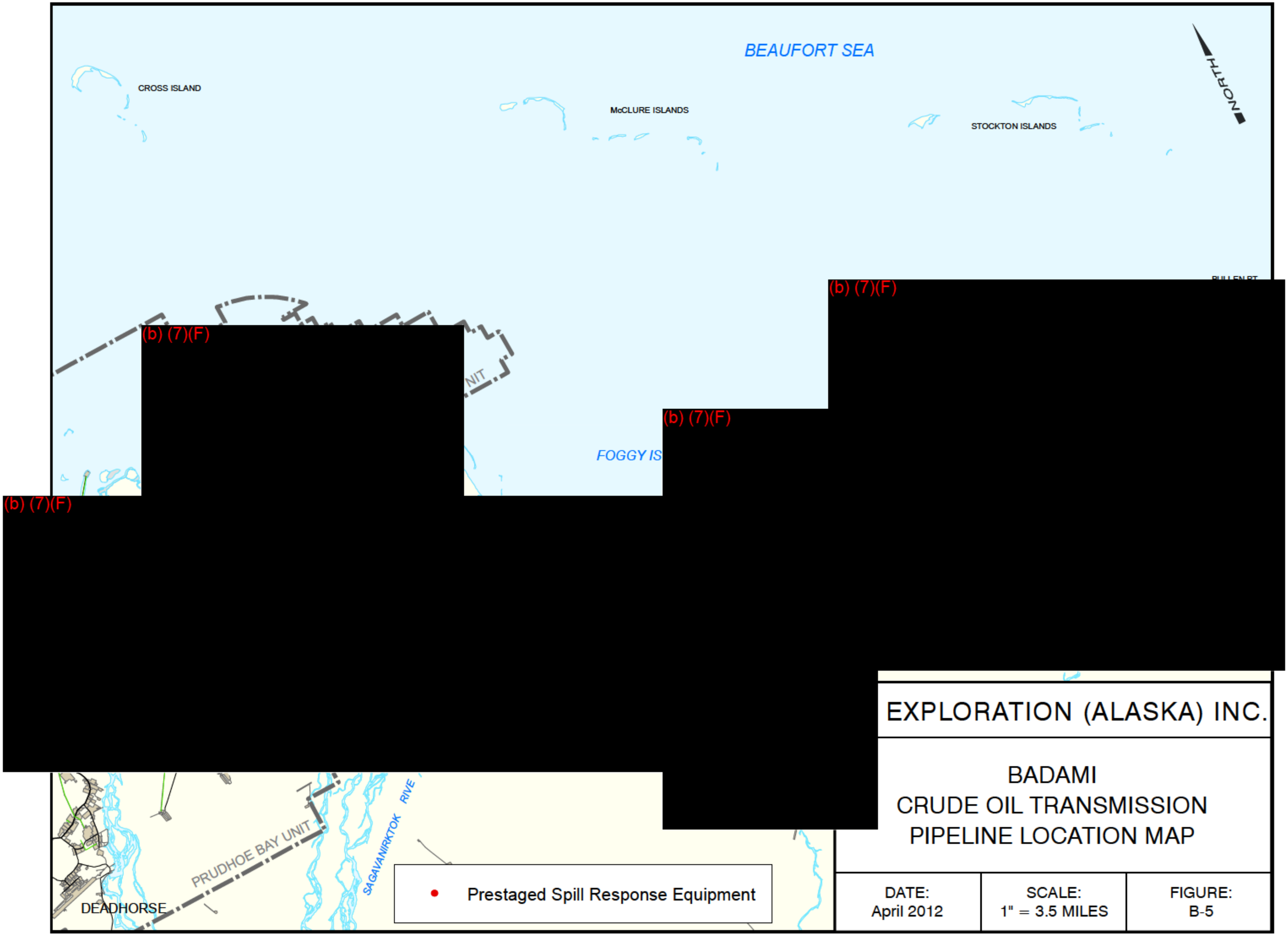
(b) (7)(F)
[redacted]
(b) (7)(F)
[redacted]
BP EXPLORATION (ALASKA) INC.
ENDICOTT AREA
PIPELINE SCHEMATIC
DATE: April 2012
SCALE: 1" = 10,000 Feet
FIGURE: B-4



sp15667v.mxd

APPENDIX C

ENDICOTT-BADAMI DISCHARGE HISTORY

APPENDIX C: ENDICOTT AND BADAMI DISCHARGE HISTORY TABLE (SEPTEMBER 1992 THROUGH AUGUST 2011)

Field	Date	Material	Gallons	Tundra / Water	Event Description	Environmental Impact	Preventive Action	Clean-Up Action
Endicott	11-Oct-92	Fresh Water	74.0	N	During well injection, 2 barrels of muddy water rose out of a nearby well cellar. Spill was caused by a thaw bulb which extended between the injection well and nearby well, allowing fluids to travel outside the casing strings between the cement and the formation. Although no muds reached the surface, hydraulic connectivity allowed surface formations waters to be forced to the surface by the mud volume.	None. All material was contained on the pad.		Contaminated material was scraped up with a bucket loader and a super sucker was used.
Endicott	14-Oct-92	Drilling Mud	200.0	N	Vibration of the hard line injection line sheared the nipple, causing the line to fail at the injection wellhead.	None. All material was contained on the pad.	A flexible hose will be used to go from the injection line to the well head.	A bucket loader was used to scrape up contaminated material.
Endicott	13-Mar-93	Drilling Mud	840.0	N	While pumping mud returns into waste mud injection tank, operator failed to shut down valve in time to prevent overfilling of tank.	None.	Review fluid transfer proceedures with operators. All fluid transfers to a tank require continual monitoring.	Used supersucker.
Endicott	12-Mar-99	Hydraulic fluid	103.0	N	Pipe fitting to a supply valve was leaking, possibly due to thermal expansion (Tioga heater) and over-pressurization.	None, contained to the gravel pad.	Review operation and maintenance SOP's of the hydraulic system for the wells, including the use of heaters. Remind personnel not to leave heater hoses in the well houses unattended for extended periods of time.	The fluid in secondary containment was vac'd up and recycled. Fluid on the gravel was soaked up with absorbents, and contaminated gravel scraped up.
Endicott	1-Jun-99	Hydraulic fluid	60.0	N	SSSV was found closed due to a hydraulic fluid leak inside the hydraulic control panel in the wellhouse. A failed swagelock connection was found on the balance line supply. The ferrule had been crimped too close to the end of the tubing.	None, contained to the pad.	Evaluate the installation hydraulic tubing and fittings on the system.	Hydraulic fluid on the gravel was cleaned up with absorbent pads and a small amount was shoveled out.
Endicott	17-Jun-99	Diesel	200.0	N	The diesel fuel day-tank for the fire-water pump was overfilled, causing diesel to be spilled outside the skid through an atmospheric vent. Tank is equipped with a high-level alarm and is isolated from a pressurized header by a single block valve. It appears that fuel leaked across the block valve causing the tank to overfill. Failure of the high-level alarm delayed recognition of the problem.	None, contained to the pad.	Repair and calibrate level transmitter and high-level alarm. Service leaking, single block valve. Initiate a PCR for adding another block valve in the fill line and extending the tank vent line closer to the ground and installing secondary containment.	Contaminated gravel has been fully excavated to the maximum extent possible.
Endicott	12-Aug-99	Crude oil	110.0	N	Hose failure during sales meter certification. Used hose rated for 150 psi, since the pump would only discharge about 110 psi. Meter prover certification operation was discussed during pre-job safety meeting. The piping/hose/pumping system was set up, pressure tested, and circulation started. After approximately 3 1/2 hours, at 90 psi, the pump discharge hose came apart at the crimp. Oil sprayed out until the pump could be shut down.	None, contained to gravel pad.	Procure and use hard line for this annual certification.	Soaked up puddled oil with absorbent, scraped up contaminated gravel with loader.
Endicott	15-Sep-99	Crude Oil	75.0	N	Leaking flowline from well. Investigation found loose bolts on a flange on the flowline. Bolts became loose most probably from flowline vibration and line slugging.	None.	Start quarterly PM for all slugging and vibrating wells.	Pick up with Bobcat and sorbent pads.
Endicott	6-Oct-99	Seawater/ Produced Water	100.0	N	1st Stage Separator Sandjet Water Supply Piping Failure. The leak was coming from a drain point on the sand-jet water supply piping. The failed component was a nipple between the weld-o-let and the drain valve. The nipple was filled with solids and had severe internal corrosion.	None, contained to pad.	Corrosion engineer will evaluate pipe and recommend corrective action.	Fluids that puddled or in secoundary containment, vacced up, contaminated gravel scrapped up.
Endicott	16-Dec-99	Crude Oil	1,700.0	N	Operator started filling dead crude storage tank, level indicated 57%. Operator then assisted with MI compressor testing. Short time later he called control room crude tank level; still at 57% and no high level alarm had been activated. Operator shut-in fill line and called instrument technican to check operation of level indication. After checking out level indication operator went outside to storage tank containment and found tank had overflowed.	None, contained to secondary containment.	Procedure will be changed to have the level indicator and high level alarms function tested before filling tank each time.	Crude oil will be vacced out.
Endicott	22-Dec-99	hydraulic oil	185.0	N	Wing valve actuator hydraulic seal failure.	None	Investigate wing valve seal PM.	Suck up with vacuum truck
Endicott	25-Jan-00	Crude oil	550.0	N	Well 2-04 is under frequent surveillance and has had multiple replacement of piping due to erosion/corrosion. Wellhead tech noticed oil spray from wellhouse. Leak was from 1st elbow downstream of choke. Probable cause is vibration.	None, contained to pad.	Review inspection frequency, and well bore velocities when well is brought on and during normal flow.	Vac up produced water/crude oil in cellar and recycle into plant. Wipe down tree and walls with absorbant. Scrape up contaminated gravel.
Endicott	17-Feb-00	Crude oil	170.0	N	Operator was draining "B" meter run on the meter prover skid. The drain system is hard piped into an automated sump. Short time later the control room received a high level sump alarm and a status run on the sump pump. The operator went to bottom floor of skid to check sump and found it overflowing.	None.	Follow existing procedure OIL-118 more closely. Review in operator tool box.	Cleaned up with shop vacs and absorbents.
Endicott	21-Feb-00	MEG	200.0	N	Glycol heat trace tubing ruptured on a produced water process line.	None, contained to pad.	Unknown, at this time.	Contaminated snow, ice and gravel scraped up.
Endicott	7-Jul-00	hydraulic oil	175.0	N	DCS warning notified board operator of low level in hydraulic tank. A hydraulic panel was found to be leaking a large amount of hydraulic fluid. The fitting was inspected and found to be an original part improperly made up with the ferrule set too far forward.	None.	Expedite plant change to show level changes in hyd. supply tank at smaller amounts.	Hydraulic oil contaminated gravel removed and placed in cont. gravel pit.

APPENDIX C: ENDICOTT AND BADAMI DISCHARGE HISTORY TABLE (SEPTEMBER 1992 THROUGH AUGUST 2011)

Field	Date	Material	Gallons	Tundra / Water	Event Description	Environmental Impact	Preventive Action	Clean-Up Action
Endicott	26-Sep-00	Lube Oil	100.0	N	Gasket on Hydrualic plate blew out. Improper gasket material was used.	None	Replace gasket with more appropriate material and check to see if there are other possible places where a gasket failure could take place before starting turbine.	Sorbent Pads, vacced up free liquids.
Endicott	23-Apr-01	Crude Oil Produced Water	75 555	N	Endicott Production & Wells Coordinator spotted a cloud of vapors emanating from a well house. The control room was immediately contacted by radio and the well remotely shut-in. It was discovered that a needle valve had broken off the production flowline drain nipple, allowing produced fluids to escape to the well house.		The fitting has been replaced with a less bulky unit that should reduce stress on the fitting nipple.	Vac truck was used to remove fluids from well cellar. Sorbents and hand tools were used to remove oil from outside of containment.
Endicott	21-Mar-03	Produced Water	4,410.0	N	During pig launching, an o-ring in the receiver door failed, resulting in a spill. The investigation showed that there was some corrosion to the face of the receiver barrel where the o-ring blew out. It is believed that the corrosion was due to the application of a corrosion inhibitor without water dilution.	None expected.	Investigation still in progress, corrective action forth-coming.	Fluid from inside the module was cleaned up using a vac-truck and mops. Clean-up of gravel and snow to be completed using heavy equipment.
Endicott	6-Feb-06	Hydraulic Fluid	165.1	N	Hydraulic leak from well. The SSV Actuator needle valve to tubing connection had loosened and leaked fluid to lined well cellar and the gravel floor of the well house.	None, all material contained in sealed well cellar and confined to well floor.	Continue, and emphasize visual inspections of wells by well tenders.	Used vac truck to pull standing fluid from lined cellar, used hand tools to recover contaminated gravel.
Endicott	15-Aug-06	Produced Water	65.9	N	Prior to plant shutdown, the master, SSV and wing valves of water injection well were closed and the swab valve was opened to provide a high point bleed. The inter island water pipeline and produced water injection header were pressured up in order to push water out of the pipeline, which resulted in a leak when the water was pushed through the wing valve and out of the swab valve.	None, all of the fluids were contained in the well cellar.	Close valves prior to pressurizing system.	The standing fluids were removed with the use of a vac-truck. Gravel was removed with a super sucker.
Endicott	24-Sep-06	Lube Oil	60.1	N	A seal oil leak occurred from main gas compressor seal oil control panel on to the module floor. A needle valve was left cracked off of seat, which allowed it to leak out the common drain. During the plant shutdown there had been considerable activity in and around the seal oil panel, with all the gauges and pressure switches being recalibrated and the HP seal oil pump replaced. This valve may have either been bumped open then or never fully tightened post-calibration.	None, all the spilled material was in containment.	Review incident in tool box meetings with all operations and maintenance crews. Insure all valves are closed prior to compressor restart.	The lube oil was vacuumed up from module floor.
Endicott	26-Sep-06	Produced Water	100.0	N	Produced water sprayed out of stem on pig launcher discharge valve. Mechanic looked at the valve and found that the stem seal had failed.	None, all of the spilled material was in secondary containment.	Replace seal in the 14" pig launcher line.	The spilled material was squeeged into a sump.
Endicott	23-May-07	Hydraulic Fluid	144.9	N	The hydraulilc seal on the SSV (surface safety valve) actuator failed.	None, all fluid contained in lined cellar.	Change out actuator valve.	Used vacuum truck to pull standing fluids, used absorbents to wipe down well tree and lined floor.
Endicott	20-Jan-08	Produced Water	210.0	N	A drain valve mounted on the end of the 3-phase production header at SDI developed a bonnet leak, releasing oil/gas/water. Operations shut in the SDI wells and eventually the entire facility in order to facilitate depressuring of the affected production header.	None.	Investigation initiated to determine root cause(s) and corrective actions to prevent recurrence.	Contaminated snow was hand shoveled and supersucker will remove bulk material.
Endicott	28-Feb-08	Crude Oil	233.1	N	While returning a meter run prover inlet block valve to service after performing maintenance, crude oil was inadvertantly drained through an open drain valve to the module floor sump resulting in 233 gallons of crude oil overflowing the sump onto the module floor.	None.	Review written energy isolation (safe out) procedures for valve maintenance on these meters and meter prover and ensure proper procedure is followed for maintenance on this specific valve.	Mop, squeegee, and flush crude oil back into the same sump that overflowed.
Endicott	7-Mar-10	Diesel	100.0	N	While greasing a tree on a shut-in well, a worker used a brass hammer tap on the valve seat next to the grease fitting valve to check it. The hammer glanced off the quick-connect on the grease manifold, causing it to disconnect. Diesel, under pressure (approximately 500 psig), was released from the tree.		The worker quickly removed the grease manifold from the grease supply line, opened the bleeder and reconnected the manifold to the tree and closed the bleeder. This stopped the release.	Majority of fluid was contained in lined cellar Wellhead and house walls were hand wiped with rags & sorbents
Endicott	26-Mar-10	Emulsion Breaker	100.0	N	After filling the Emulsion Breaker day tank, the fill block valve was left open 1 quarter turn.	None. All material contained in built-in containment under bulk tank farm.	Ensure operators completely close this valve on Day Tank T-E3-1102-1 instead of completely closing this valve then purposefully rotating it back 1/4 rotation. Consider adding redundant block valve.	Snow melting through June & July was adaquate to allow the removal of standing water and emulsion breaker to be removed from secondary containment. Area was washed down to remove any residue and all waters and trace of product removed using vac truck.

APPENDIX C: ENDICOTT AND BADAMI DISCHARGE HISTORY TABLE (SEPTEMBER 1992 THROUGH AUGUST 2011)

Field	Date	Material	Gallons	Tundra / Water	Event Description	Environmental Impact	Preventive Action	Clean-Up Action
Endicott	13-Jun-10	Diesel	130.2	N	Fuel truck stopped on soft shoulder on road from SDI to MPI when he was pulled over by security. When the driver pulled away from his stopping point the soft gravel would not let him turn back towards the center of the causeway. The truck was then pulled off towards the side of the causeway. The truck continued down the steep shoulder and rolled onto its side.	None		Placed containment under the leaking hatch atop the truck. A vac truck was used to removed the remaining diesel from the rolled over vehicle. The initial phase of the cleanup consisted of placement of boom and digging a trench at the edge of the spill area. Any filtration of liquid into the trench was removed using a vac truck. A front end loader was used to excavate the contaminated gravel.
Endicott	11-Feb-10	Diesel	100.0	N	A slow drip of diesel fuel coming from a welded seam on the bottom of the fuel tank containment leaked onto a snow covered liner. Approximately 100 gallons leaked to secondary containment with about 0.1 gallon leaking onto snow and ice inside of the spill liner beneath the fuel tank. Inspection of the tank revealed that a valve to attach sight glass tubing had failed creating a slow leak source.	None; 0.1 gallons that was released onto snow on-pad from secondary containment was shoveled up and placed back into secondary containment, vacuumed and sent for hydrocarbon recycle.	Ensure fuel tanks are regularly inspected and snow and ice removed from secondary containment after adverse weather.	Fuel vacuumed from containment and fuel tank. Heat placed on tank to melt residual snow and ice inside for removal. Contaminated snow from 0.1 gallons that breached secondary containment was shoveled back into containment, melted, vacuumed and sent to Endicott for hydrocarbon recycle via the Endicott snowmelt tank.

The discharge history from September 1992 through August 2011 was reviewed. No hydrocarbon spills greater than 55 gallons were reported at Endicott between February 11, 2010 and August 31, 2011.