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

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

1.1.1 Operator and Contacts

The operator covered by this plan is:

ExxonMobil P.O. Box 196601 Anchorage, AK 99519 (907) 561-5331	Street Address: 3301 C Street, Suite 400 Anchorage, AK 99503 Fax: (907) 564-3789

For additional information contact Larry Harms, Regulatory Manager, (907) 564-3779.

1.1.2 Response Levels

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

- Level I: Small operational spill dealt with by on-scene personnel and equipment,
- Level II: Larger spill which could affect the area around the facility or operation and that uses equipment and/or trained personnel from the other operating areas of the North Slope, or
- Level III: A major spill response using resources from off the North Slope.

The Safety, Health and Environment (SHE) Lead or designated ACS Technician will assume the role of Incident Commander for a Level I incident. The Drilling Supervisor will serve as the Initial Incident Commander in a Level II/III incident involving a drilling-related incident, until relieved. During the construction phase, the Construction Site Superintendent will act as the Initial Incident Commander in a Level II/III incident. The Production Field Superintendent will act as the Initial Incident Commander in a post-construction Level II/III incident. The Incident Commander or designee will be responsible for making sure that safety is considered in response decisions and that internal notifications are completed.

Level II and III spills may involve activation of the IMT, the North Slope Spill Response Team (NSSRT), and the ExxonMobil North American Regional Response Team (NARRT). As necessary, ExxonMobil will use the resources of other North Slope operators through ACS, Mutual Aid, spill response cooperatives, and contractors.

The Point Thomson IMT response organization structure described in this plan is based on the Incident Command System (ICS) and is described in ACS *Technical Manual*, *Volume 3, Incident Management System*.

ACS *Technical Manual, Volume 3*

If all or part of the IMT is activated, the Incident Commander will be responsible for directing the organization's efforts from the Command Post at Point Thomson or the Emergency Operations Center in Anchorage. In the initial stage of a spill emergency, the Incident Commander will:

- Contact ACS to request ACS equipment support.
- Consult with the On-Site Incident Commander or on-site response team members, as appropriate, on the present status of the spill (continuing or controlled), the volume of the spill, and the status of containment and cleanup efforts.
- Consult with appropriate regulatory agencies.
- Consult with the Federal On-Scene Coordinator (FOSC; either USCG or EPA) on conditions affecting slick movement.
- Identify specific equipment and personnel needs.
- Facilitate the acquisition and provision of equipment, personnel, and other resources to respond to the spill.
- Establish a Command Post at Point Thomson.
- Establish and maintain necessary radio, telephone, and communication facilities at the Command Post.

The Incident Commander will be in charge of the on-site IMT personnel in the event of a major spill. The Incident Commander has the authority to commit ExxonMobil and contractor resources available in the area to contain and cleanup oil spills. Additionally, the Incident Commander will be responsible for overall site management, including the following:

- Establishing response priorities and determining how the response will be implemented.
- Establishing the Command Post.
- Coordinating well control activities.
- Authorizing contract labor, equipment, and support services.
- Approving oil spill containment and cleanup procedures.
- Agency notification and liaison (in the absence of the SHE Lead).
- Authorizing response team personnel to request permits for burning, dispersant application, and shoreline response techniques.
- Informing ExxonMobil management about response activities.

The IMT is organized and staffed to conduct a major oil spill response operation. Personnel on the IMT have appropriate training and work experience to provide guidance and make decisions essential for ensuring that oil spills, regardless of size and location, are cleaned up in accordance with procedures that are environmentally acceptable. Also, personnel filling these positions are familiar with oil spill response techniques for use in the Beaufort Sea area.

Specific Information for a Well Event

If a well control-related spill is detected, the first priority will be to determine the source of the spill and, if possible, to shut it off immediately and then notify the Drilling Supervisor as soon as possible. In the event of an oil spill, the Drilling Supervisor has the authority and responsibility to take appropriate response actions and notify ExxonMobil management.

ExxonMobil has assigned responsibilities and provided authority to response team members to implement response actions in the event of a spill or blowout. The Drilling Supervisor will be the on-site authority during drilling operations and will be responsible for initially directing the Point Thomson Spill Response Team (SRT) and well control activities. The Drilling Supervisor will also be responsible for ensuring that the Drilling Operations Superintendent is promptly notified of spills. In the event of a blowout in which liquid hydrocarbons could lead to a major spill, the Drilling Supervisor, at his discretion, will have the authority to ignite the blowout as a means of source control and personnel safety.

The Drilling Supervisor will be responsible for directing immediate response using personnel, equipment, and on-site materials for spills at all levels. In a major spill event, Level II or III, the Drilling Supervisor will be responsible for field operations as the Incident Commander until relieved by the Drilling Operations Superintendent. He will specifically be responsible for:

- Initiating immediate actions to safeguard personnel, minimize environmental damage, and protect property.
- Notifying production personnel to shut in all wells on the affected pad.
- Assessing the situation to permit an effective first response, including immediate voluntary ignition.
- Notifying the Drilling Operations Superintendent of the situation and recommending a higher level response, if necessary.
- Planning and directing further response actions using available on-site resources.
- Authorizing mobilization of additional resources.
- Notifying government agencies in the absence of the Drilling Operations Superintendent, or if instructed to do so.

Note that ExxonMobil has provided the authority for igniting the blowout to the Drilling Supervisor. Approval of this ODPCP by the State of Alaska constitutes endorsement and pre-approval of voluntary ignition for source control.

The Drilling Operations Superintendent, based in Anchorage, has primary responsibility for Incident Command and calling out the IMT.

The Drilling Operations Superintendent will make the following decisions in a Level II or III response as quickly as possible:

- In the event of a blowout, how best to initiate forward actions, including surface intervention alternatives, assistance from specialists, relief well planning, etc.
- Whether to initiate procedures to obtain approval for the use of *in situ* burning (ISB) or chemical agents.
- Whether to request equipment from sources other than ACS.

These decisions will be made on the basis of information provided by the Drilling Supervisor and will be sensitive to the need to act decisively in order to maximize the protection of the environment.

The Drilling Supervisor will direct operations at the site to bring the well under control by surface techniques. This may entail:

- Working with the Incident Commander and well control specialists to assess well and rig equipment conditions for applicability of surface control techniques.
- Implementing well ignition procedure, if the situation escalates.
- Maintaining communications with the Incident Commander throughout the operation and providing progress reports.
- Informing the Logistics Section Chief of personnel, equipment, and supply requirements.
- Documenting actions related to well control.

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

1.2.1 Internal Notification Procedures

It is ExxonMobil policy for employees and contractors to report spills of oil, regardless of size, to an ExxonMobil representative. The spill observer will report a spill to his/her supervisor, and if the supervisor is unavailable, to Security. Figure 1-1 shows immediate spill notifications and Figure 1-2 shows the Point Thomson IMT. Tables 1-1A and 1-1B provide checklists of the immediate response and notification actions for a spill. The primary on-site IMT members will be determined before construction begins.

ACS *Technical Manual, Volume 3*

FIGURE 1-1
IMMEDIATE SPILL NOTIFICATIONS

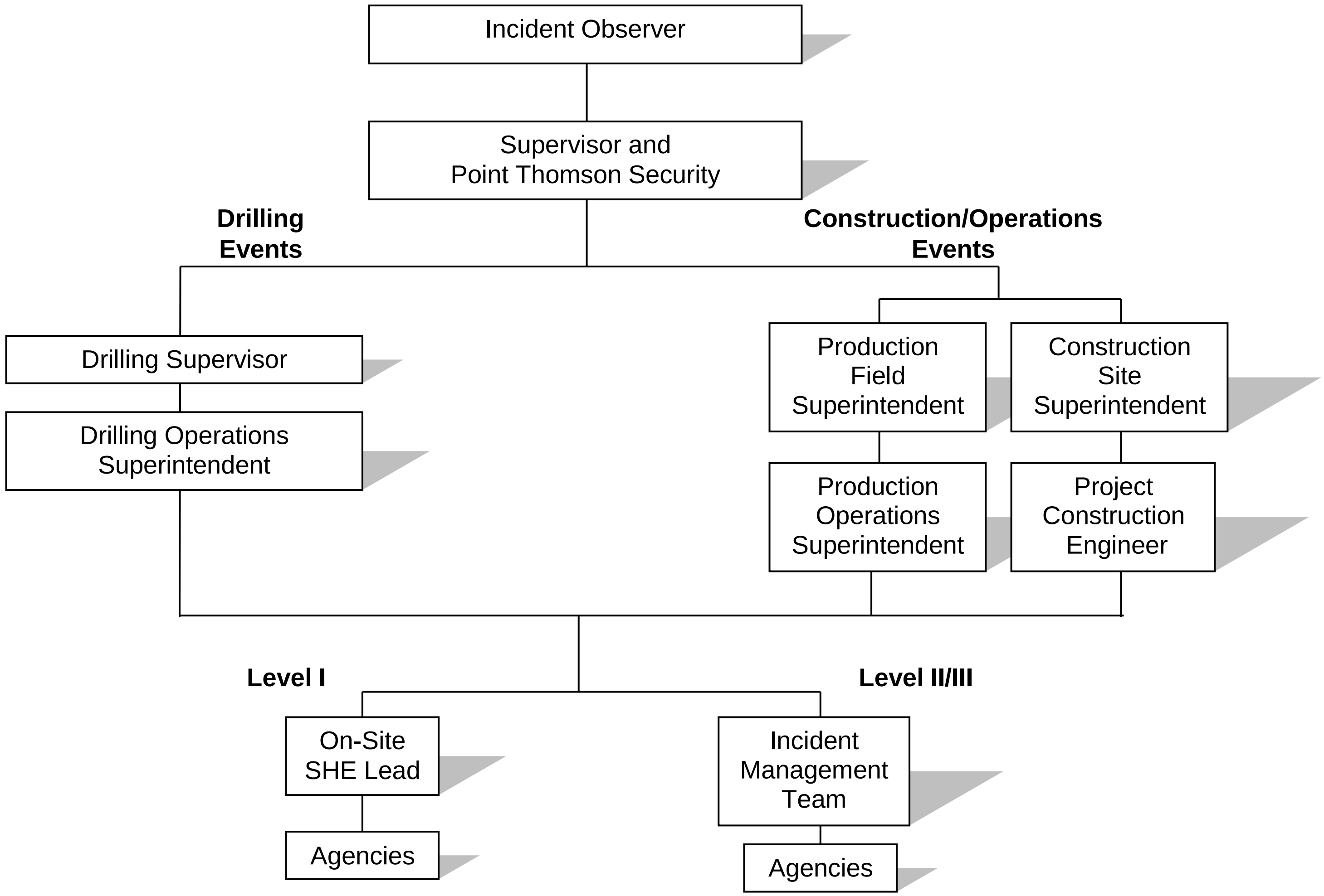

FIGURE 1-2
POINT THOMSON INCIDENT MANAGEMENT TEAM FOR LEVEL II/III

INCIDENT COMMANDERS

Drilling Supervisor – Well Control Incident
TBD

Construction Site Superintendent – Construction Phase
TBD

Production Field Superintendent – Operations Phase
Chris Faulk

OPERATIONS SECTION CHIEFS

Matt Koenig
Project Construction Engineer
(281) 654-6384

Construction Supervisor
TBD

PLANNING SECTION CHIEFS

Larry Harms
Regulatory Manager
(907) 564-3779

Mike Barker
Permit Specialist
(907) 564-3691

LOGISTICS SECTION CHIEF

Tony Yacob
(713) 656-3318

Charlie Jones
(907) 564- 3704

FINANCE SECTION CHIEF

Pat Hughes
(907) 564-3680

Wanda Grba
(907) 564-3714

WELL CONTROL OPERATIONS SECTION CHIEF

TBD by ExxonMobil

TABLE 1-1A
IMMEDIATE ACTION CHECKLIST

LEVEL I SPILL RESPONSE	
PERSONNEL	**ACTION TO BE TAKEN**
FIRST PERSON TO SEE THE SPILL	Assess safety of situation, determine whether source can be stopped, and stop the source of spill if possible. Immediately notify supervisor and radio operator or Security. Dial _____ (TBD) or channel _____ (TBD) on radio. Provide information on: • Personnel safety • Source of the spill • Type of product spilled • Amount spilled • Status of control operations
SECURITY	Immediately notify: • SHE Lead • Safety Coordinator • Supervisor of Drilling, Construction, or Operations
INCIDENT COMMANDER, ACS LEAD TECHNICIAN, OR SHE LEAD	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 (Table 1-3). If necessary, mobilize Point Thomson SRT and on-site equipment required to control and cleanup spill. Upon arrival on scene, begin response operations. Assess response activities. If response is adequate, remain at Level I. If additional capabilities are needed, go to Level II or III response. 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.

If the SHE Lead or ACS Lead Technician determines that the spill is a Level II or III event, the additional notifications indicated in Table 1-1B will take place.

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TABLE 1-1B
IMMEDIATE RESPONSE AND NOTIFICATION ACTIONS

LEVEL II OR LEVEL III SPILL RESPONSE	
SECURITY	Immediately notify: · Point Thomson SRT Lead · SHE Lead · Qualified Individual · Production Field Superintendent, Drilling Supervisor, and Construction Site Superintendent · Contractors, Personnel, and Management
SAFETY OFFICER	Account for the safety of all personnel. Determine whether a threat of fire or explosion exists. If a threat exists, suspend control and response operations, and notify Fire/Safety Department. Determine appropriate personal protective equipment (PPE) and brief site workers.
SHE LEAD	Make immediate phone notification to the agencies. ACS holds permits that need to be activated. Prepare cleanup and waste management plan for agency approval. Ensure agency notifications are complete. Maintain follow-up notifications on a periodic basis and whenever there is a significant change in the course of a reported incident.
INCIDENT COMMANDER, DRILLING SUPERVISOR, CONSTRUCTION SITE SUPERINTENDENT, OR PRODUCTION FIELD SUPERINTENDENT	Activate all or part of the IMT and NARRT. Notify ExxonMobil Security at Anchorage Headquarters (HQ), (907) 561-5331. Provide Security with a contact name and phone number. Continue internal and external notifications. Coordinate staff activity. Manage incident operations and approve release of major resources and supplies. Notify production personnel to shut in all wells on the affected pad.
OPERATIONS SECTION CHIEF	Activate ACS, (907) 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, personnel, 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 all aspects of the response. Provide environmental and permitting support as needed.
LOGISTICS SECTION CHIEF	Order equipment, personnel, material, and supplies as requested. Provide transportation support. Provide support for field operations and Command Post operations.
FINANCE SECTION CHIEF	Issue cost code for tracking of expenses. Notify insurance representatives as warranted. Track expenditures and provide audit function as needed.

TABLE 1-1B (CONTINUED)
IMMEDIATE RESPONSE AND NOTIFICATION ACTIONS

LEVEL II OR LEVEL III SPILL RESPONSE	
WELL CONTROL OPERATION INCIDENT COMMANDER	Determine if incident requires well control specialist, and if so, contact: Wild Well Control, Inc.: (281) 353-5481 24-hour emergency number. Cudd Well Control (a Division of Cudd Pressure Control): 1-800-990-CUDD 24-hour emergency number, (713) 849-2769 world-wide number. Critical Well Coordinator at Prudhoe Bay (907) 659-2805.
WELL CONTROL OPERATIONS SECTION CHIEF	Identify well control options based on circumstances of incident. Notify rig contractors and coordinate activities. Implement logistics plan to provide support for the well control specialists.

A Spill Report Form will be completed for reportable spills. See Figure 1-3 for an example.

The on-site ExxonMobil Drilling Supervisor will be notified as soon as possible of oil spills associated with Point Thomson drilling operations. The Drilling Supervisor is responsible for ensuring that the Drilling Operations Superintendent in Anchorage is promptly notified of spills. The Drilling Operations Superintendent based in Anchorage will notify the company management and advise it of the response effort and whether the spill threatens a sensitive area. He will provide management with preliminary information on the size of the spill, whether it is continuing, whether the spill is moving toward a sensitive area, and the estimated time to arrive.

The Production Field Superintendent is responsible for ensuring that the Production Operations Superintendent is promptly notified of spills associated with construction and operations. The Construction Site Superintendent at Point Thomson will report spills to the Project Construction Engineer based in Anchorage.

1.2.2 External Notification Procedures

The Incident Commander or designee is responsible for notifying the regulatory agencies of oil spills. Agency notification information is provided in Tables 1-2 and 1-3. See Section 3.3 for a description of the command system, including the Incident Commander and those members of the IMT who notify agencies.

ACS Tactic A-2

1.2.3 Qualified Individual Notification and Responsibilities

During the drilling phase, the Drilling Supervisor will be the QI, during the construction phase, the Construction Site Superintendent will be the QI and during the production phase, the Production Field Superintendent will be the QI. These individuals will be on-site during drilling, construction, and production activities.

In the event of a spill requiring notification of the Federal On-Scene Coordinator (FOSC), the QI will be notified and will respond. In the event the primary QI is unavailable, the alternate QI will respond.

The prerequisites for designation of a QI are:

- Available on a 24-hour basis,
- Speaks English fluently,
- Located in the United States,
- Trained as a qualified and alternate QI under the response plan, and
- Familiar with the emergency response plan and its implementation.

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

- Activate and engage in contracting oil spill removal organizations and other response-related resources,
- Act as a liaison with the Federal On-Scene Coordinator, and
- Acquire funds to carry out response activities.

FIGURE 1-3
SPILL REPORT FORM

ExxonMobil SPILL INCIDENT REPORT **DATE OF SPILL:**

☐ **ExxonMobil Spill** ☐ **Contractor Spill** ☐ **Sighting**

The following information must be reported immediately (within 1 hour) to the Regulatory Compliance Group (RCG). The RCG has the primary responsibility for making telephone notifications. Make voice contact with the RCG (907-561-5331), to flag that a report will be forthcoming. This report should be completed without delay and sent via computer to the Regulatory Contact or faxed to 907-564-3789. On weekends or holidays, call the Weekend Duty contact. If unable to notify an ExxonMobil Regulatory Contact, then the person-in-charge (PIC) is responsible for the required telephone notifications. The National Response Center telephone number is 800-424-8802.

FIELD/PLANT	**RIG**	**LEASE #**	**NAME OF RECEIVING WATER BODY**
SECTION, TOWNSHIP, RANGE	**LATITUDE** **Deg. Min. Sec.**	**LONGITUDE** **Deg. Min. Sec.**	
TIME SPILL OBSERVED	**TIME SPILL STOPPED**	**SPILL SIZE ON WATER** **Length: Width:**	

VOLUME SPILLED ON LAND		**VOLUME SPILLED ON WATER**	
MATERIAL SPILLED	**ESTIMATED VOLUME**	**MATERIAL SPILLED**	**ESTIMATED VOLUME**

Slick Color(s): Give estimated percent coverage for each color observed

Barely Visible		**Silver Sheen**		**Slight Rainbow**		**Bright Rainbow**	
Dull Colors		**Yellowish Brown**		**Light Brown**		**Dark Brown/Black**	

Environmental Conditions

Wind direction from:	**Speed: MPH**	**Air Temperature: °F**
Wave Height: ft.	**Current Direction to the:**	**At: Knots**

Atmosphere (check applicable condition)

Clear ☐	**Partly Cloudy** ☐	**Overcast** ☐	**Hazy** ☐	**Fog** ☐	**Rain** ☐

DESCRIPTION OF SPILL INCIDENT:

PRELIMINARY CAUSE:

REMEDIAL ACTIONS:

NOTIFICATION LOG

AGENCY NOTIFIED/REPORT #	**DATE**	**TIME**	**PERSON NOTIFIED**	**NOTIFICATION MADE BY**

COMMENTS:

REPORT PREPARED BY: **DATE:** **TIME:** hrs.

TABLE 1-2
EXXONMOBIL CONTACT LIST

POSITION	NAME	TELEPHONE
EXXONMOBIL MANAGEMENT, HOUSTON		
Point Thomson Project Manager	R. Buckley	(281) 654-4054
Point Thomson Project Construction Engineer	M. Koenig	(281) 654-6384
Field Drilling Manager	P. Altimore	(281) 654-4428
Production Operations Manager	TBD	TBD
EXXONMOBIL MANAGEMENT, ANCHORAGE		
Headquarters Security (24-hour)		(907) 561-5331
Alaska Interest Organization Manager	J. Williams	(907) 564-3689
Regulatory Manager	L. Harms	(907) 564-3779
Drilling Operations Superintendent	TBD	TBD
Production Operations Superintendent (Alt. QI)[1]	C. McClain	TBD
Project Construction Engineer	TBD	TBD
FACILITY CONTACTS, POINT THOMSON		
Security (24-hour)	TBD	TBD
Drilling Supervisor (QI)[1]	TBD	TBD
Construction Site Superintendent (QI)	TBD	TBD
Safety, Health and Environment Lead	TBD	TBD
Regulatory Compliance Group	TBD	TBD
ACS Environmental Technician	TBD	TBD
Production Field Superintendent (QI)[1]	C. Faulk	TBD
WELL CONTROL SPECIALISTS		
Wild Well Control, Inc. (24-hour)		(281) 353-5481
Cudd Well Control, a Division of Cudd Pressure Control (24-hour)		(800) 990-CUDD
World-Wide Number		(713) 849-2769
Critical Well Coordinator at Prudhoe Bay		(907) 659-2805
ALASKA CLEAN SEAS, OSRO		
Address: Pouch 340022, Prudhoe Bay, Alaska 99734		
Prudhoe Bay Office		(907) 659-2405
Operations Manager		(907) 659-3202

HQ Security will provide notification to ExxonMobil management and spill response teams on a 24-hour basis.

[1] The primary and alternate Qualified Individuals will be updated prior to construction.

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TABLE 1-3
AGENCY REPORTING REQUIREMENTS FOR OIL SPILLS

AGENCY	SPILL SIZE	VERBAL REPORT	PHONE NUMBERS	ALASKA CONTACT	WRITTEN REPORT
National Response Center (Notifies all appropriate federal agencies)	See specific federal agency below for guidance on reportable spill size	Immediately	(800) 424-8802 (24-hour)	24-hour line	Not required as form is completed during phone notification process
EPA	Any size to navigable waters of the U.S. (includes tundra) or to land that may threaten navigable waters	Immediately	(907) 257-1342 (M-F, 8-5) (206) 553-1263 (907) 271-3424 (FAX) (M-F, 8-5)	Carl Lautenberger Seattle office, 24-hour EPA fax number	For facility requiring SPCC Plan if spill is 1,000 gallons or more or if it is second spill in 12 months
USCG	Any size in or threatening navigable waters	Immediately	(907) 271-6700 (24-hour) (907) 271-6751 (FAX)	Marine Safety Office USCG fax number	Not required, but requested
DOT	**>**5 gallons ; no report required for release less than 5 barrels resulting from pipeline maintenance activity[1]	Immediately[2]	(800) 424-8802	24-hour line	Required within 30 days on DOT Form 7000-I (see form for details)
U.S. Department of the Interior, U.S. Fish and Wildlife Service (USFWS)	Any size that poses a threat to fish and wildlife	Immediately	(907) 271-2797	---	---
U.S. Department of the Interior, Minerals Management Service (MMS)	All spills into marine waters	Immediately	(907) 271-6065 (24-hour) (907) 271-6504 (FAX)	Jeff Walker	Copies of any reports submitted to ADEC as soon as possible
Pipeline Coordinators Office (State Pipeline Office [SPCO]/DOT) - Anchorage, AK	Any size from a regulated pipeline	Immediately	(907) 271-4373	---	---
ADEC, Northern Alaska Response Team	ON WATER Any Volume	Immediately	(907) 451-2121 (907) 451-2362 (FAX) and (800) 478-9300 (M-F after 5, Sat, Sun)	Ed Meggert ADEC fax number or Alaska State Troopers	Fax immediately after verbal report; a follow up report within 15 days of end of cleanup
	ON LAND 1 to 10 gallons	Within 48 hours of knowledge of the spill			Include in monthly written report; a follow-up report within 15 days of end of cleanup.
	>10 to 55 gallons	Within 48 hours of knowledge of the spill			Include in monthly written report; a follow-up report within 15 days of end of cleanup.
	>55 gallons	Immediately			Fax on same day spill occurs

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

AGENCY	SPILL SIZE	VERBAL REPORT	PHONE NUMBERS	ALASKA CONTACT	WRITTEN REPORT
ADEC, Northern Alaska Response Team (Continued)	IN SECONDARY CONTAINMENT <55 gallons	None	(907) 451-2121 (907) 451-2362 (FAX) and (800) 478-9300 (M-F after 5, Sat, Sun)	Ed Meggert ADEC fax number or Alaska State Troopers	None
	>55 gallons	Within 48 hours of knowledge of the spill			None
Alaska Department of Natural Resources (ADNR)	ON LAND <1 gallon to gravel pad or road; ice pad or road	None	(907) 451-2678 (907) 451-2751 (FAX)	Spill Report Number ADNR fax number	None
	1 to 10 gallons	Within 48 hours of knowledge of the spill			None
	>10 to 55 gallons	Within 48 hours of knowledge of the spill			None
	>55 gallons	Immediately			None
	IN SECONDARY CONTAINMENT <55 gallons	None			None
	>55 gallons	Within 48 hours of knowledge of the spill			None
Alaska Oil and Gas Conservation Commission (AOGCC)	All spills from wells or involving any crude loss	Immediately	(907) 279-1433 (24-hour) 276-7542 (FAX) (907) 659-3607 659-2717 (FAX)	Sarah Palin	Within 5 days of loss

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

AGENCY	SPILL SIZE	VERBAL REPORT	PHONE NUMBERS	ALASKA CONTACT	WRITTEN REPORT
North Slope Borough (NSB)	ON WATER Any Volume	Immediately	(907) 852-0440 (Barrow) (907) 852-0322 (FAX) (907) 852-0284 (Local Emergency Planning Committee [LEPC]-Barrow) (907) 852-6111 or (907) 852-2995 (NSB police-Barrow) (907) 428-7000 (State Emergency Planning Committee [SEPC]-Anchorage)	Permitting and Zoning Dept. Waska Williams, Office of Safety and Environmental Affairs (OSEA)	None
	ON LAND (gravel pad or road; ice pad or road; snow-covered tundra) >55 gallons	Immediately			None
	IN SECONDARY CONTAINMENT >55 gallons	Within 48 hours of knowledge of the spill			None

1. 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
   - Is confined to company property or pipeline right-of-way AND cleaned up promptly.

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; or
   - Was significant in the operator's judgment even though it did not meet the criteria.

1.2.4 Written Reporting Requirements [18 AAC 75.300]

Depending on the type and amount of material spilled, individual government agencies have written reporting requirements that must be adhered to by ExxonMobil.

Regulation 18 AAC 75.300 requires notification to ADEC of spills on state lands or waterways. After notification of the discharge has been made to ADEC, the Department will, at its discretion, require interim reports until cleanup has been completed. A written final report must be submitted within 15 days of the end of cleanup operations, or if no cleanup occurs, within 15 days of the discharge. ExxonMobil's interim and final written reports will meet the requirements that are specified in 18 AAC 75.300 and will contain the following information:

- Date and time of discharge;
- Location of discharge;
- Name of facility or vessel;
- Name, mailing address, and telephone number of person or persons causing or responsible for the discharge and the owner and the operator of the facility or vessel;
- Type and amount of each hazardous substance discharged;
- Cause of the discharge;
- Description of any environmental damage caused by the discharge or containment to the extent the damage can be identified;
- Description of cleanup actions taken;
- Estimated amount of hazardous substance cleaned up and hazardous waste generated;
- Date, location, and method of ultimate disposal of the hazardous substance cleaned up;
- Description of actions being taken to prevent recurrence of the discharge; and
- Other information the Department requires to fully assess the cause and impact of the discharge.

USDOT and USEPA notification and reporting procedures will also be followed in the event of a discharge. See Table 1-3.

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

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

- ACS *Technical Manual* includes site entry procedures, site safety plan development, and personnel protection procedures.
- *Alaska Safety Handbook* distributed to all North Slope employees and contractors.
- ExxonMobil *Production Safety Manual.*

ACS Tactics S-1 through S-6

- ExxonMobil *Emergency Response Guide* written to aid in responding to events or situations that might arise from ExxonMobil activities or operations that pose, or could pose, a threat to the safety and welfare of people, the environment, ExxonMobil assets, or others.

Evacuation plans will be maintained on-site at the Point Thomson facility.

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

ExxonMobil's Point Thomson communications are designed for compatibility with the communications equipment available through ExxonMobil's Anchorage office and ACS's North Slope Emergency Response Communication Network. Initially, Point Thomson will respond using the day-to-day communications system.

The frequencies assigned to Point Thomson are as follows:

- To be determined prior to construction activities.
- To be determined prior to construction activities.

During drilling and construction, a C-band satellite Earth station will provide standard voice (telephony) and data capabilities to/from the Point Thomson field location and Deadhorse, as well as to locations external to the North Slope region. A single-site VHF/UHF repeater system will also be provided at the Point Thomson field location to provide local Company radio traffic as well as Contractor construction activities, VHF marine, and ACS oil-spill response communications. These radio systems will facilitate two-way communications between vehicles and personnel in and around the drill site. The UHF (Company-operated) equipment located at the drill site will consist of a base station and a minimum of four rechargeable hand-held portable radios. At least four additional portable units are available at Deadhorse. The spare units can be quickly mobilized to the drill site by air or, during the first two years, by ice road. The stand-alone VHF ACS oil-spill response equipment will consist of a base station and a minimum of four rechargeable hand-held portable radios and two mobile units.

Prior to Point Thomson tie-in to the ACS Wide Area Radio System (via the planned Point Thomson – Deadhorse microwave system), the Badami ACS oil spill repeater and coast station will be used for spill response communications as needed. In the event of a spill at or near the Point Thomson location, additional UHF repeaters would be installed on the existing Badami tower (by ACS) pointing easterly in the direction of Point Thomson. These UHF repeaters will be capable of remote control by the ACS Centracom dispatch console at Deadhorse via the existing Badami – Deadhorse microwave connection. ACS would then extend coverage from Badami by setting up portable shelters and repeaters along the spill route. The stand-alone VHF ACS oil-spill response equipment installed at Point Thomson would act as a supplementary radio system to the existing Badami ACS oil-spill response system.

At Point Thomson, an ACS wooden console (VHF base, UHF base, and VHF Marine Base), pipemounts and roof antennas will be installed after power generators are installed at the central facility.

Before production startup, an oil spill repeater system (OS-45) with antenna will be installed on the Point Thomson facility tower. Two single-channel remote controls will be installed in association with this repeater system. After installation and commissioning of the planned Point Thomson – Deadhorse microwave system, the Point Thomson oil spill repeater system will be connected to the ACS Slope-wide radio system (via the Point Thomson – Deadhorse microwave system). The control point for the system is the ACS Base in Deadhorse.

Also for production startup, a marine private coast station (Marine Channel 9) with an antenna on the Point Thomson tower will be installed in the facility. They will be connected to ACS Base in a manner similar to the oil spill repeater.

In addition, the following equipment will be available at Point Thomson for oil spill response: Ten Motorola VHF hand-held radios with speaker microphones, spare batteries and individual and multi-chargers, two Motorola VHF mobile radios, two hand-held global positioning system (GPS) units and two bagphone cellular phones.

A cell site repeater at the Point Thomson facility will be obtained through Arctic Slope Telephone.

The Point Thomson VHF repeater provides for a direct tie-in to the ACS communications system. With such repeaters installed across the North Slope, coverage is provided from Alpine to Point Thomson. The range of each fixed repeater is approximately 30 to 50 miles, depending on topography. ACS solar-powered or generator-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 to allow for effective spill response, when necessary in an emergency.

Where required, the self-contained ACS communications module will be mobilized for use by ExxonMobil. The ACS Mobile Command Center and the Staging Area Manager's office are equipped with various radio, bush phone, and microwave equipment to provide communications to the field. This capability coordinates the NSSRT with the *North Slope Operating Area Frequency Plan*, and includes access to mobile communication channels.

A detailed explanation of oil spill communications on the North Slope is provided in the ACS *Technical Manual*.

ACS Tactic L-5

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

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

Procedures for initial transportation of equipment and personnel to the spill site rely on equipment based at Point Thomson and at other North Slope facilities. Transportation options vary with the season and other factors.

The general alternatives and estimated travel times are listed in Tactics L-3 and L-4 of the ACS *Technical Manual*. Actual transportation times vary with weather, safety considerations, wildlife considerations, and terrain. Illustrations of transportation strategies are found in the scenarios in Section 1.6.14.

ACS Tactics L-3 and L-4

Estimated travel times for initial responses to oil spills at Point Thomson are listed below:

- Central Processing Facility (CPF): 10 minutes.
- Production well pads by vehicle from CPF: 1/4 - 1/2 hour.
- Production well pads by vehicle on ice road from Prudhoe Bay: 2 hours.

- Condensate export pipeline by helicopter (when available): 1/2 hour.
- Condensate export pipeline by Rolligon (when available) and all-terrain vehicles (ATVs): 5 hours.
- Point Thomson dock from West Dock by vessel: 9 hours.
- CPF from Deadhorse by fixed-wing aircraft (when available): 1/2 hour.

The wide variety of transportation modes provides alternatives in adverse weather conditions. Rolligons, helicopters, and fixed-wing aircraft are options for transportation in all seasons. Vehicles are options for reaching Point Thomson during the two winter seasons in which an ice road links the road system to Point Thomson. Vessels are options from July to October. See Figure 1-4.

When poor visibility and icing conditions limit air transportation and the use of landing strips, ground and vessel transportation provide alternatives depending on the season. Low temperatures and wind do not directly affect land transportation options. White-out conditions affect air and land transportation options similarly.

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

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

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

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

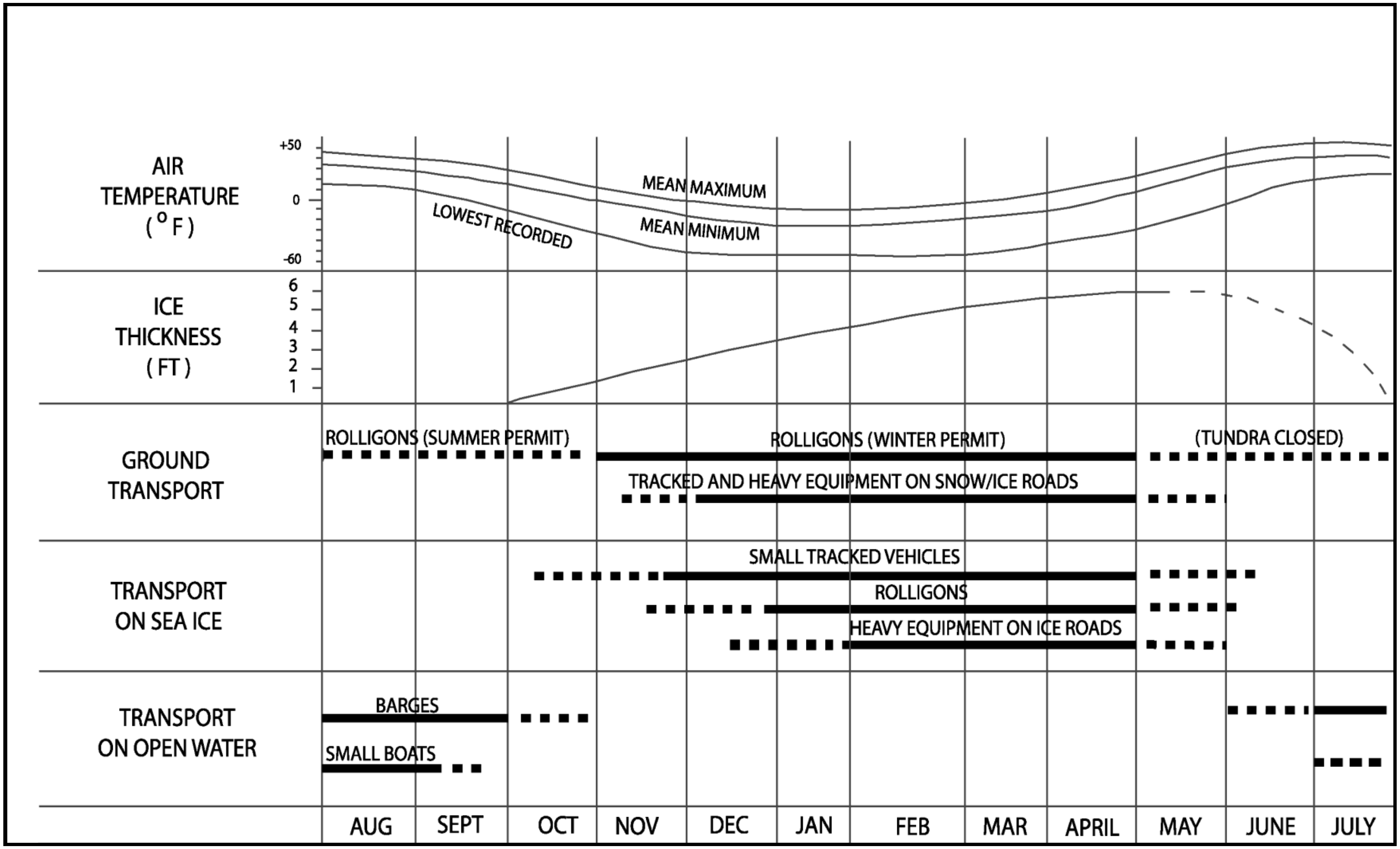
1.6.1 Procedures to Stop Discharge [18 AAC 75.425(e)(1)(F)(i)]

Module Shutdown

Safety Instrumented Systems (SIS), independent of the Process Control System (PCS), will serve to protect equipment and personnel from process upset and emergency conditions. In the event the PCS fails to keep the process within specified operating limits, these dedicated safety systems will provide for the safe shutdown of equipment and process units. The safety systems will include dedicated process sensors that activate dedicated output devices and do not rely on functions controlled by the PCS.

These safety systems, while functioning separately, will have data links to the PCS for purposes of monitoring and activating the safety functions from the Central Control Room (CCR) panels. Additional switches will be provided in proximity to the protected systems for activation of shutdown by personnel in the field.

FIGURE 1-4
SURFACE TRANSPORT SEASONS



In order of priority, the purposes of the safety systems are to:

- Protect personnel from an abnormal condition,
- Protect the environment,
- Protect equipment from damage, and
- Safely isolate problem areas to allow production to continue, if possible.

There will be a minimum of three levels of shutdown at the Point Thomson facilities as follows:

- **Process Shutdown (PSD).** Process systems are isolated during a PSD either by critical process variable alarms or operator action. PSDs are segregated by process systems such as the production wells, condensate processing train, condensate stabilization, condensate shipping, flash-gas compression, high-pressure gas injection compression, gas injection wells, and produced water handling. A PSD isolates the specific process system while the remaining process systems either remain on-line, or are brought to a safe condition automatically or by operator action.
- **Emergency Shutdown (ESD).** An ESD isolates the entire CPF processing system while maintaining operation of the utility and safety systems. An ESD is activated either by critical process alarms, fire or gas detection alarm, or by operator action. The ESD will isolate the well pads and production streams entering the plant, and the condensate export system leaving the plant, and will depressurize the isolated section where the incident is detected. If possible, the gas injection wells will remain on-line to maintain a supply of gas for the fuel gas system and the process systems will remain at pressure. Freeze protection procedures will be initiated if the shutdown is expected to be for an extended period of time. All utility systems will remain on-line to ensure safe plant shutdown and to maintain life support systems.
- **Total Plant Shutdown (TPS).** Following an ESD, if it is determined that the field is to be shut down, a TPS is initiated. If the field is to be restarted in the near term, the freeze protection operations will be completed before initiating the TPS. If the TPS is the result of an emergency, all the process systems are depressurized to the flare with the last system depressurized being the fuel gas system and the gas injection lines from the central injection pad. In either case, the normal power generation system is isolated while the essential power generator is brought on-line. During the TPS, utility systems are isolated and shut down either automatically or by operator intervention, as dictated by the severity of the emergency event and the rapidity of the intervention required to ensure a safe and orderly response.

Condensate Handling System

In an ESD, all hydrocarbon lines entering and leaving the plant will be shut in, wells will be shut in to prevent overpressure of the pipelines, and the first-stage separator, pumps, and motors will be turned off.

Well Pads and Manifolds

The well shut-in will be automated and response times kept at a minimum. The design of the well shut-in system follows the shutdown philosophy discussed below.

The Point Thomson wells will have a master “Christmas tree” surface safety valve (SSV) that is hydraulically actuated, an SSV on the well-line wing, and a surface-controlled subsurface safety valve (SSSV) that can shut in the well. The SIS for the wellheads will actuate these valves in the event of a shutdown, and the valves will shut and wells will cease producing. The SSVs are a “fail closed” design (loss of hydraulic pressure results in the closing of the SSVs). Two manual valves on the tree can be closed by Operations personnel to provide further isolation. Lines connecting producing wells at Point Thomson will be equipped with low-pressure sensors used to isolate producing wells in the event of a leak. If the pressure in a line drops below a set limit, the line will shut in. Operations personnel performing routine checks would identify small leaks that would not activate the low-pressure sensor. If a small leak is identified, manual steps will be taken immediately by Operations personnel to isolate the leak.

Maintenance of Shutdown Systems

Systems will receive periodic testing and maintenance. Provisions are made to deactivate the shutdown system while testing and maintenance are in progress.

Pipeline

Isolation valves can be activated to minimize discharge from the condensate export pipeline. The control room operator, under the direction of the Operations Team Leader, can initiate a pipeline ESD to close the automated main outlet valve. The pipeline ESD will automatically close valves. The control room operator can then verify valve closure of the isolation valves with a distributed control system (DCS) indication.

1.6.2 Fire Prevention and Control [18 AAC 75.425(e)(1)(F)(ii)]

Each module will be equipped with fire and gas detectors at various locations within the module. The type and number of fire and gas detection devices will vary from module to module, depending on the service of the equipment in the module. The systems will be electrically supervised against short- and open-wiring faults in the detection and alarm circuits. The electrical power supply is supported by the uninterruptible power system.

Fire Detection System

Fire detection systems in process facilities will use infrared (IR) flame detectors which detect the infrared radiation produced by a fire. Triple IR technology will be used, which uses programmed algorithms to correlate the data received by three sensors within each detector. The electrical power supply will be supported by an uninterruptible power supply (UPS).

Gas Detection System

Gas detection systems in process facilities are generally integrated as a part of the SIS. The electrical power supply will be supported by a UPS. The gas detection equipment will be selected to identify the concentration of a particular gas, which closely aligns with the composition of any potential gaseous leaks.

Generally, if a gas concentration above an established low level (generally 10 to 20 percent of the lower explosive limit [LEL]) is detected by a gas detector, area ventilation will be stepped-up from low speed (typically 6 air changes per hour) to high speed (typically 12 air changes per hour), and alarms will be sounded in the module and the CCR. If one or more gas heads are detected above an established high level (generally 40 to 60 percent), multiple alarms will activate and the process systems in the area will be isolated and blown down.

Automated Methods

Fire detection and alarms will be controlled by a control panel or a dedicated computer system. The automated systems will be responsible for monitoring the fire alarm detection systems within the field of operation.

Alarms Initiated by Detectors

The ICSS will receive alarms from fire and gas controls and annunciate alarm status. The alarms will light up and sound, as appropriate, in the CCR and the affected areas. Examples of alarms that the DCS will receive are high or low gas alarms and fire alarms.

Response to Alarm Signals from Detectors

Personnel will respond to alarms by locating the alarm point and identifying whether the alarm represents a true condition. Personnel safety is the first priority throughout this process.

The fire detection systems will automatically initiate fire suppression release where suppression systems are installed, and isolate and blow down the process systems located in the area.

Manual Bypass of Automated Systems

Technicians who test and perform maintenance on the sensory equipment will first isolate the discharge circuit to prevent the accidental release of fire suppression. Board Operators will receive an alarm indicating the system has been bypassed.

Once the manual fire suppression by pass panel is active, the following will occur:

- The system by pass is entered on the defeated safety device log,
- Fire alarms will not cause a fire suppression dump,
- Electric pull stations will not release fire suppression, and
- If a fire suppression release condition should occur during a system by pass, the operators will use the manual fire suppression dump mechanism.

The defeated (by passed) Safety Devices Standard/Procedure is a critical operating procedure outlined in ExxonMobil's Operations Integrity Management System (OIMS) that establishes a procedure to authorize, record, and monitor all defeated safety devices by means of a master log called a Defeated Safety Device Log.

After any fire suppression system by pass, a system of work permits and other administrative controls specify the requirements for reactivating the system and will ensure the system is not left disabled.

Visual Detection of Fires

If equipment fires occur outside the range of automated detection systems, and are detected visually, there will be two methods of notification as follows:

- Manual fire alarms can be activated to initiate the automated systems and response activity.
- Fires can be reported to the CCR by calling the designated emergency number. A red phone specifically dedicated for incoming emergency calls is reached by dialing an assigned code, such as 911 or 000. Communications will activate the response teams.

1.6.3 Blowout Response [18 AAC 75.425(e)(1)(F)(iii)]

ExxonMobil considers surface intervention, supplemented with voluntary well ignition in the event of unrestricted flow, represents Best Available Technology (BAT) for well source control during exploration or production well blowouts. However, provisions for drilling a relief well are maintained as required by 18 AAC 75.455(d)(2). The general logic regarding response to a surface blowout is described in Figure 1-5A, and Figure 1-5B shows the Well Ignition Decision Tree.

If well control is lost, resulting in an uncontrolled flow of fluids at the surface, detailed planning will begin in order to regain control. A thorough evaluation of the situation will be necessary to determine the best course of action. There are three primary considerations in developing a blowout response plan, based on the specific well conditions, as follows:

- Access to the well/site that ensures personnel safety;
- Well status, including the location of the release and whether ignition has occurred; and
- The best method for quickly regaining well control and minimizing pollution.

See Table 1-4 for Drilling Supervisor actions.

Blowout Well Ignition

Because ignition of the well may be necessary to facilitate safety during surface intervention and control activities, or to minimize environmental impact, ExxonMobil may elect to voluntarily ignite the blowout at the well.

The decision by ExxonMobil to voluntarily ignite a blowout (except for immediate concerns with ensuring personnel safety) will be made after assessing the probability of implementing successful surface control, reviewing potential safety hazards, and addressing pertinent environmental considerations.

Table 1-5 outlines well ignition procedures and lists the well ignition equipment that will be stored at Point Thomson.

FIGURE 1-5A
GENERAL SURFACE INTERVENTION OPTIONS

FIGURE 1-5B
WELL IGNITION DECISION TREE

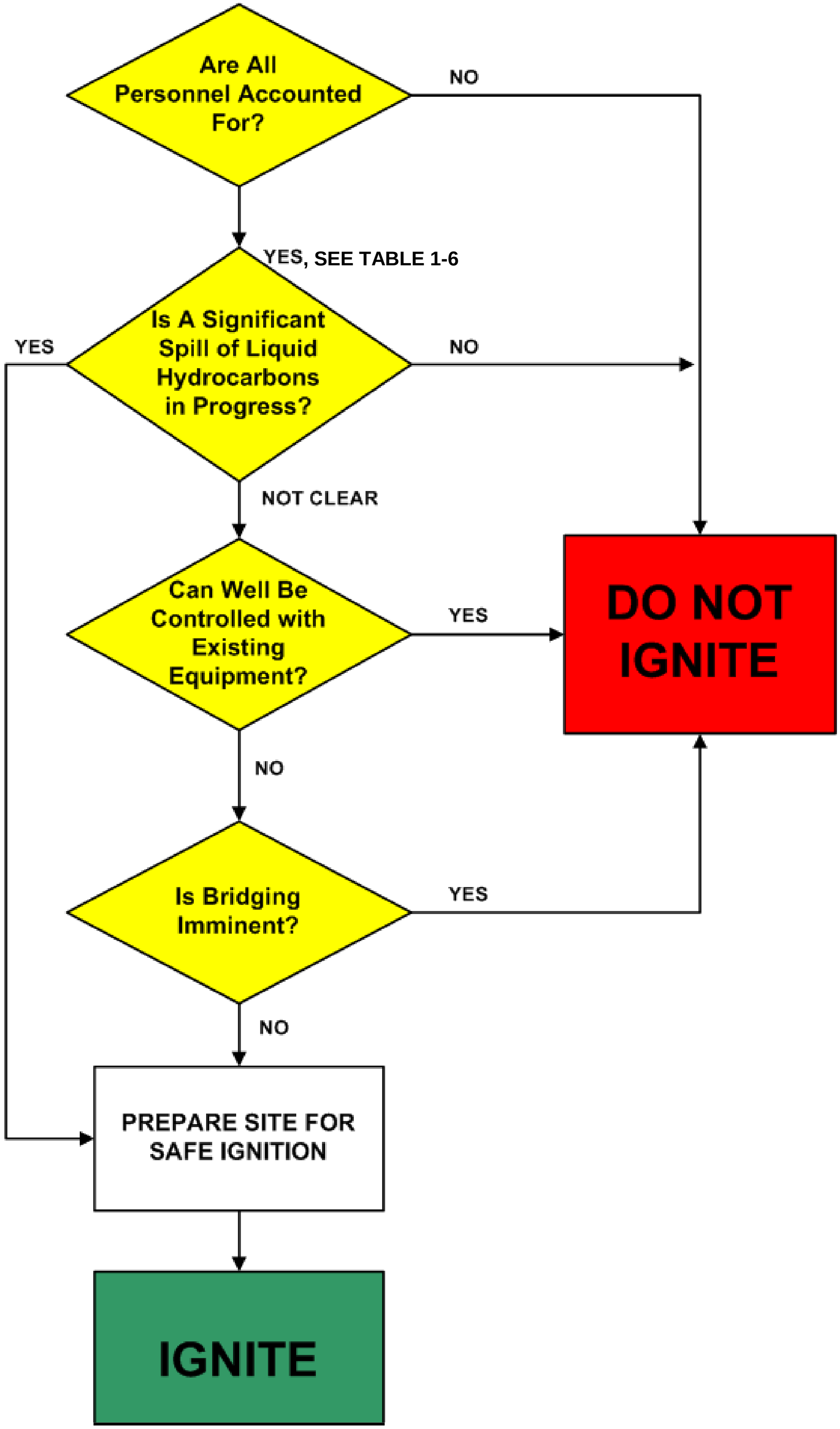


TABLE 1-4
DRILLING SUPERVISOR CHECKLIST FOR IMMEDIATE BLOWOUT RESPONSE

PERSONNEL	1. Activate alarms and evacuate hazardous areas, assemble in predesignated area, take roll call. 2. Search for missing personnel if safe to do so. If gas is present, use the buddy system, breathing apparatus, and combustible gas detectors. 3. Administer first aid and arrange for evacuation of injured personnel. 4. Arrange transport of personnel to remote, safe area if situation requires.
WELL CONTROL	1. Extinguish all ignition sources. 2. Make preliminary well condition assessment: whether the well is burning, danger of ignition, type of fluid, approximate rate, location of flow, wellhead and BOP integrity, status of rig equipment, etc. 3. Initiate immediate well control actions judged to be safe and practical with the resources on location. 4. Notify the production supervisor to shut in all wells on the affected pad.
EQUIPMENT	Move response equipment and vehicles a safe distance from the well for later use in control and cleanup efforts.
OIL SPILL COUNTERMEASURE	1. Divert oil flow away from quarters and rig equipment. 2. Notify the production supervisor to shut in all wells on the affected pad.
REPORTING	As soon as practical, notify the Drilling Operations Superintendent. A Spill Report and a Well Control Emergency Report form should be completed as soon as practical and sent by facsimile to the Drilling Operations Superintendent.

TABLE 1-5
EMERGENCY WELL IGNITION PROCEDURES

EQUIPMENT	1. Explosimeter/gas detector (2), and spare batteries 2. Self-contained breathing apparatus (2) 3. 500-foot lengths of safety retrieval rope (2) 4. Meteor-type flare gun (1), and spare flare
PROCEDURE	1. Evacuate all personnel to a safe distance upwind from the well. To avoid a major explosion, well ignition should not be attempted unless the wind speed is a minimum of 5 miles per hour (mph). 2. The ignition team consists of (a) two personnel wearing breathing apparatus with body harnesses; and (b) personnel to tend the ropes and pull either person to safety if he is overcome by fumes. 3. Select a firing point and approach route that is upwind, no closer than necessary to the blowing well, and affords the greatest degree of protection and accessibility. 4. One person is responsible for monitoring the explosimeter and the other is responsible for firing the flare. 5. Approach the well along the upwind approach route until the explosimeter indicates the presence of combustible gas. Back up along the approach route 100 yards, and fire the flare to ignite the well. Do not fire the flare unless the explosimeter confirms that it is safe to do so.

Prior to actually igniting the well, the Drilling Supervisor would confirm that personnel are safe.

The circumstances for igniting an uncontrolled well blowout are those circumstances that the rig supervisor could readily determine at the time, and in which ignition would maintain safety and minimize environmental damage. For several potential well blowout situations, the relationship between ignition effects and safety and environmental protection thresholds have previously been clearly established. Those limited circumstances are defined in Table 1-6 as the terms for the pre-authorization for well ignition.

TABLE 1-6
CONDITIONS FOR PRE-AUTHORIZED WELL IGNITION

1.	Other wells on the well pad are shut-in.
2.	Personnel are evacuated beyond the expected radius of collateral damage.
3.	Without ignition, the volume of oil reaching the surface and remaining uncontrolled is expected to exceed 100,000 gallons (2,400 barrels [bbl]).

Time is of the essence, so a decision on voluntary ignition would be reached as soon as possible. ExxonMobil's plan would be to reach a decision within 2 hours.

Surface Control Options

In the unlikely event that well control is lost while drilling a well, every effort would be made to provide control at the surface. Historically, regaining control at the surface is fast and successful. Because an uncontrolled flow at the surface would present a safety hazard, specific safety procedures would be employed to protect personnel, the environment, and equipment.

Source control could be accomplished either through natural means or direct surface intervention. The most common natural means would be formation bridging which occurs due to wellbore collapse caused by subsurface pressure changes during the blowout.

Loss of surface control maximizes the pressure drop across the formations, which maximizes rock stress and, therefore, the probability of natural bridging. Under bridging conditions, the wellbore becomes restricted and flow at the surface decreases or ceases. While surface control could be regained through natural bridging, additional mechanical methods may also be employed. The surface control methods depend on the situation. Well ignition, either accidental or deliberate, does not significantly affect the timeline for regaining well control using surface control methods since on-site equipment could be used to remove debris and permit access to the well.

Potential mechanical surface control methods include the following:

- Pumping mud or cement down the well to kill it.
- Replacing the failed equipment, if control was lost due to equipment failure.
- Plugging leaks in surface equipment, enabling circulation and ultimately the ability to regain well control.
- Removing some of the BOP stack and installing a master valve.

- Removal of existing surface BOP and perhaps wellhead equipment and replacement with a well capping stack. (This method would require diversion of existing flow to allow equipment installation.)

The critical path prior to choosing a specific method for regaining surface control, whether the well is ignited or not, is as follows:

1. Mobilize emergency response personnel and equipment,
2. Conduct a site assessment,
3. Develop safe access and work plans, and
4. Divert uncontrolled fluids for collection and handling to create a safe working environment and to minimize pollution.

The activities would be expected to take approximately one to two days. After these preparations, actual control methods could be implemented. The estimated duration to perform a full capping operation would be 15 days.

ExxonMobil will maintain contracts with well control firms to assist in the intervention and resolution of well control emergencies. 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. Providers of such services include, but are not limited to, Cudd Well Control, Wild Well Control, Safety Boss, Halliburton Energy Services, Anadrill Schlumberger, Baker Hughes INTEQ, Dowell Schlumberger, Baroid, and MI Drilling Fluids. The approved contractor will be notified immediately in the event of any well control situation that has the potential to escalate.

ExxonMobil and partners maintain and have available on the North Slope the major equipment items to initiate well capping or other surface control options. Specialized equipment for surface intervention efforts during the drilling development phase at Point Thomson is listed in Table 1-7. Equipment not located on the North Slope can be mobilized in 24 hours. Heavy lift helicopters can be mobilized from Oregon, the Pacific Northwest, or Canada and arrive at Point Thomson within three days.

Relief Well Timing

While relief well drilling is not the primary method of source control at Point Thomson, provisions for relief well drilling, including estimates of time required for controlling a blowout with a relief well, are provided.

Relief well planning would start immediately in the event of a blowout, even though relief well drilling is not ExxonMobil's primary method of source control. While detailed planning of a relief well will necessarily depend on actual well conditions when a blowout occurs, certain general site-specific plans can be made in advance. The purpose of this section is to provide the basic plan, which will:

1. Identify a surface location for each potential relief well so that the site preparation can be expedited and drilling can begin at the earliest possible time.
2. Outline the basic logistics of rig mobilization and estimate the required timing for site preparation, rig mob/demob, drilling and well-kill operations.
3. Establish the hydraulic requirements to kill a Point Thomson blowout through a relief well.

TABLE 1-7
SURFACE INTERVENTION EQUIPMENT LIST

COMPONENT	SURFACE INTERVENTION USAGE	LOCATION	AVAILABILITY
6,000 gallons per minute (gpm) Fire Pumps	Fire and heat suppression.	North Slope	<18 hours
Athey Wagons	Tractorized booms for manipulation of tools in and around blowout well.	North Slope	<18 hours
D8 Bulldozer	Power for Athey wagons and backup for heavy equipment, rig moving. Can also be used for constructing berms to aid in spill containment.	PTU	<8 hours
Backhoe	Drainage ditch, berm construction.	PTU	<8 hours
85-100-ton Crane	Heavy equipment lifting capability. If well blowout is ignited, may be needed to facilitate rig move.	PTU	<8 hours
50-75-ton Crane	Smaller, mobile units for spotting support equipment.	PTU	<8 hours
500-ton Drilling Block	Block-and-tackle system for moving or dragging heavy equipment.	North Slope	<18 hours
Drilling Line	Component of block-and-tackle system if rig moving system is inoperable.	PTU	<8 hours
20-inch and 30-inch Casing	Used to construct Venturi tubes to divert blowing well bore fluids (ignited and unignited).	PTU	<8 hours
Miscellaneous Equipment	High-pressure chicksan, flexible hoses, valves, containment boom, absorbent, and hand tools.	North Slope	<18 hours
Kill Pumps	Backup to rig pumps.	North Slope	<24 hours
Junk Shot Manifold	Manifold system constructed to pump small leak-sealing materials into well.	North Slope	<18 hours
Hot Tap Tool	Manifold used to gain safe access to pressurized tubulars at surface.	North Slope	<18 hours
Crimping Tool	Sized device used to pinch tubulars closed to seal off internal flow.	Houston, Texas	<24 hours
Abrasive Cutter	High-pressure cutting tool used to sever leaking BOPs, and rig structures.	Duncan, or Houston, Texas	<24 hours
Capping Stack	Various high-pressure BOP stacks (to replace leaking, damaged, or severed primary BOPs).	Houston, Texas	<24 hours

If Point Thomson Unit is Developed with Two Drilling Rigs

If two rigs are used to drill the Point Thomson development wells, the rig that is not drilling the blowing well would be used to drill a relief well as soon as operations with that rig are safely suspended. The two rigs are not assumed to be of equal size and capacity; the larger rig would principally drill the longer throw wells (on the West and Central pads), while the smaller rig would be used to drill shorter reach wells on all three pads. If a blowout were to occur on a long throw well being drilled by the larger rig, the question arises whether the smaller rig could drill the required relief well, given its reduced capacity to drill extended reach wells. To assure a positive answer to this question, the surface location for the relief well must be chosen such that it is technically feasible to drill the required relief well with the available rig.

In order to drill a relief well with the smaller rig to the longer-reach bottom-hole locations, the relief well surface locations could be located on an existing offshore island, i.e., Challenge Island or Mary Sachs Island. The overall drilling schedule has been planned so that, if needed, the smaller rig can be mobilized to the island without delay over ice roads during the season when transport of heavy loads over sea ice is feasible (January through April).

An additional requirement in choosing the relief well sites is that protection from explosion hazard and/or condensate from the blowout, or the combustion by-products if the well is burning, do not adversely impact the proposed location. By choosing sites that are either north-northwest or south-southeast of the pads in most instances, any undesirable effects due to prevailing winds from the east-northeast or west-southwest would be minimized. In any event, the surface locations range from about 1 to 4 miles from the blowout well surface locations, distances substantially larger than the 1,000 to 1,500 feet common in most relief well operations. Liquid and/or soot fall-out at the relief well site is therefore not expected to pose any safety or operational risk whatsoever at the relief well work site.

The sites of prior exploration/appraisal wells may be used wherever possible to minimize site preparation and drilling times, as well as disturbances to the tundra.

If Point Thomson is Developed with One Drilling Rig

If a single rig is used to drill all of the Point Thomson development wells, it would likely be severely damaged either by the blowout or from voluntary well ignition, and it could not be used for relief well drilling. In this case, a rig would be mobilized from elsewhere on the North Slope to begin drilling a relief well while surface intervention methods were being pursued.

An agreement to provide a relief well drilling rig will be in place with other operators and one or more rig contractors on the North Slope prior to the spud of the first development well.

Relief Well Logistics/Timing

Several factors contribute to the logistics and timing of relief well drilling operations, including:

1. Immediate availability of a drilling rig at PTU to drill the relief well in the two-rig development case or the potentially long mobilization time to bring in a rig from elsewhere in the one-rig case.

2. Relatively long drilling times possible due to the extended-reach and associated measured depths of many of the required relief wells.

3. Permanent roads in the development area that greatly facilitate moving the rig to most preferred relief well locations.

4. Use of existing pads from many prior wells as drill sites for the relief wells.

5. Permanent stationing of heavy equipment at PTU for site and road-building work.

6. On-site warehousing of both tangibles and consumables that would be used in the relief well.

The following are estimates of the time required for controlling a blowout using a relief well:

1)	Construction of ice road (island sites)	up to 10 days
2)	Modification of existing pad	1 to 3 days
3)	Mobilization of equipment, rig up, and preparation to spud	5 to 10 days
4)	Drilling relief well	65 to 115 days
5)	Killing blowout well	10 days
	TOTAL	81 to 148 days

These estimates exclude the time necessary to mobilize a rig from outside PTU.

The time needed for drilling a relief well varies, primarily due to the measured depth of the well, but also based on a number of unpredictable conditions, including weather, cause of blowout, and the choice of surface location. Relief well measured depths range from approximately 2,000 feet to 19,000 feet.

It would take ten days or less to mobilize any additional ice road construction equipment that may be needed and build the ice road to an island relief well location. In this instance the relief well cellar, conductor, and sheetpile could be transported to the location by Rolligon prior to completion of ice roads and be prepared for drilling.

Time Estimate to Mobilize a North Slope Rig to Point Thomson

If a rig must be mobilized from elsewhere on the North Slope to drill a relief well as in a one-rig scenario, the mobilization time would be additive to the preceding time estimates. Depending on the time of year that the blowout occurred and hence the relative difficulty of access to PTU, a substantial amount of time could be required to bring in the relief well rig.

A relief well could be initiated between January 1 and May by mobilizing a rig over ice roads. The well could be spudded within six weeks of the start of relief well pad construction.

It would take ten days or less to mobilize ice road construction equipment and build ice roads to a relief well location. This construction equipment is readily available in both Deadhorse and PTU. The relief well cellar, conductor, and sheetpile could be transported to the relief well locations by Rolligon prior to completion of ice roads and the site could be prepared for drilling. Gravel would be hauled from the local pit over permanent roads to the drill site to repair an existing well pad left from exploration/appraisal drilling operations. Upon completion of ice roads, a new pad would be constructed for the relief well. The rig would then be mobilized to the location.

If a well control problem occurs after May in a one-rig scenario and the existing rig cannot be moved off for use on the relief well, a summer mobilization of a rig by barge would be required. This scenario and timing are depicted on the lower portion of Figure 1-5C and Figure 1-5E. Open water occurs most years in the Point Thomson area by July 15; however, mobilization would occur as soon as broken-ice conditions allowed safe access by barge to the PTU dock. Barges that could transport a rig to PTU relief well locations in ten days are available at Deadhorse year-round, so a rig could be mobilized to the barges and ready to transport as soon as broken-ice conditions allowed safe access by barge. Assuming that a blowout occurs on July 15, a relief well could be spudded by late August.

Relief Well Design and Hydraulic Requirements for Well Kill

In view of the very high productivity of the Point Thomson wells, each of the relief wells will target the Thomson sand, since the entire wellbore length of the blowing well can then be used to accumulate the hydrostatic and friction pressure that are essential to accomplishing the well kill. Intermediate-depth kill attempts are not feasible for two reasons, even though the drilling time would be much shorter for such a plan: First, because of the relative well trajectories, a well that was targeted to an intermediate depth could not easily be redirected to a deeper intersection depth if the blowout could not be killed at the shallower depth. Starting a new relief well would be required, and the time spent drilling to the intermediate depth would essentially be wasted. Second, given the substantial kill requirements at the deeper intersect (to be discussed later in this section), the probability of successfully killing the well hydraulically at an intermediate depth is very unlikely.

Efficiency of pumping operations for the kill will be highest if direct inter-well communication can be established so that no fluid is lost to the formation. Achieving a direct intersect is quite feasible, but directional control and use of magnetic ranging devices will be more difficult. Not only will the relatively high angles (up to 66 degrees) of some of the well holes likely preclude the use of some gyro tools, but the performance of both directional Measurement While Drilling (MWD) and magnetic ranging tools at high latitudes will also be degraded, especially if sunspots and/or other magnetic disturbances are occurring. Tool vendors indicate that relief well operations could be slowed or halted for as much as ten days if magnetic storms are persistent; however, the vendors are confident that any needed relief well can successfully meet desired directional objectives.

Tubulars in the relief well must be sized so they are capable of delivering necessary kill fluid volumes to the blowout. As a rough approximation, the minimum cross-sectional area of the relief well available for injection should be about the same size as the corresponding area of the blowing well. In the most likely blowout scenario, flow occurs up a 9 7/8-inch casing by 5-inch drill pipe annulus. The same wellbore geometry was assumed for the initial calculation of relief well hydraulics. Because the reach of many of the potential relief wells is long, it is likely that an 11 7/8-inch intermediate liner will be required to ensure that 9 7/8-inch casing can be set prior to penetrating the Thomson reservoir.

If returns are lost in the relief well upon penetrating the blowout wellbore and/or the partially drawn-down Thomson sand, well killing operations would begin immediately. Setting 9 7/8-inch casing immediately above the Thomson sand will prevent mechanical failure of the overlying shales if relief wellbore pressures drop briefly upon initial wellbore intersection while the kill pumps are being brought on-line.

Blowout kill requirements were determined using the same proprietary wellbore simulator used to model well unloading and stabilized flow performance of the blowing well. In the case of the well kill simulations, the initial condition is a well blowing condensate and gas. Mud is then introduced into the lower section of the reservoir in the blowing well, usually at constant density and constant pump rate, and the well begins to load up with liquid mud as the simulation steps forward in time. If density and rate are held constant, there are two possible outcomes: either the well will die (in which case the pumping time and minimum required volume to stop flow from the reservoir are determined), or the well does not die (in which case the well simply stabilizes at a reduced flow rate due to the added pressure of the mud in the wellbore). If the well dies, continued simulation models the displacement of the

FIGURE 1-5C
RELIEF WELL OPTIONS DURING THE YEAR

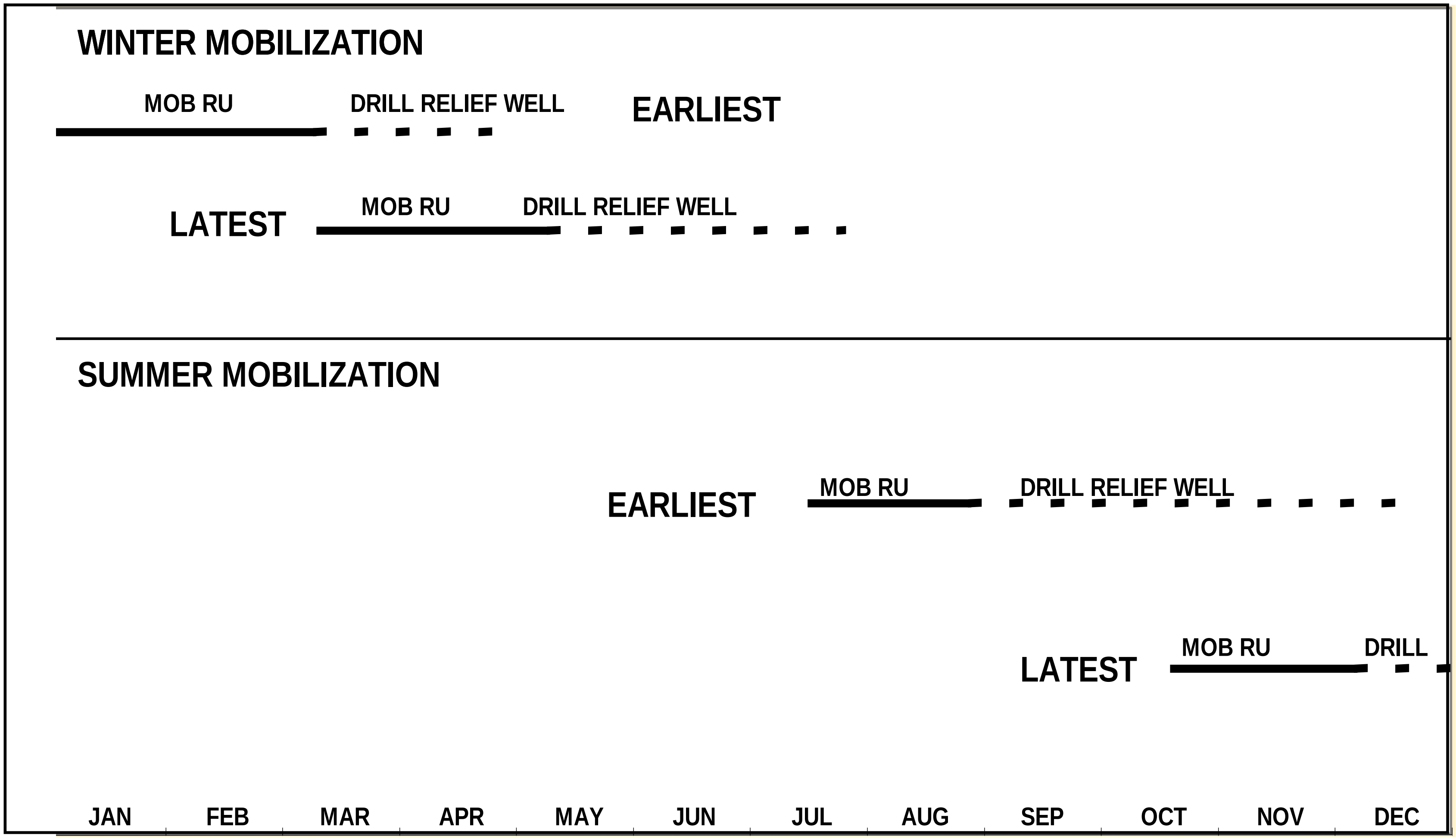


FIGURE 1-5D
WINTER MOBILIZATION FOR RELIEF WELL

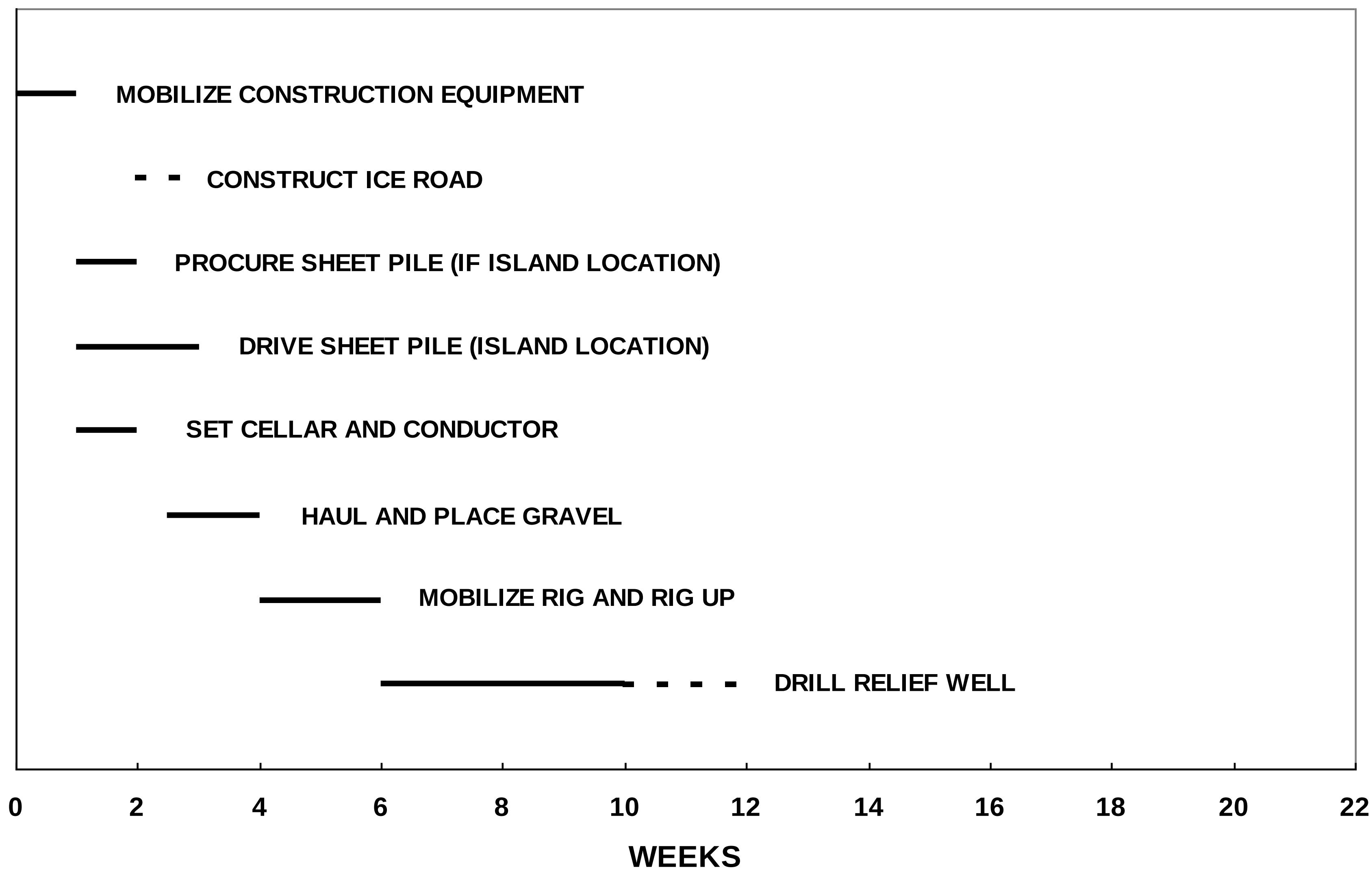
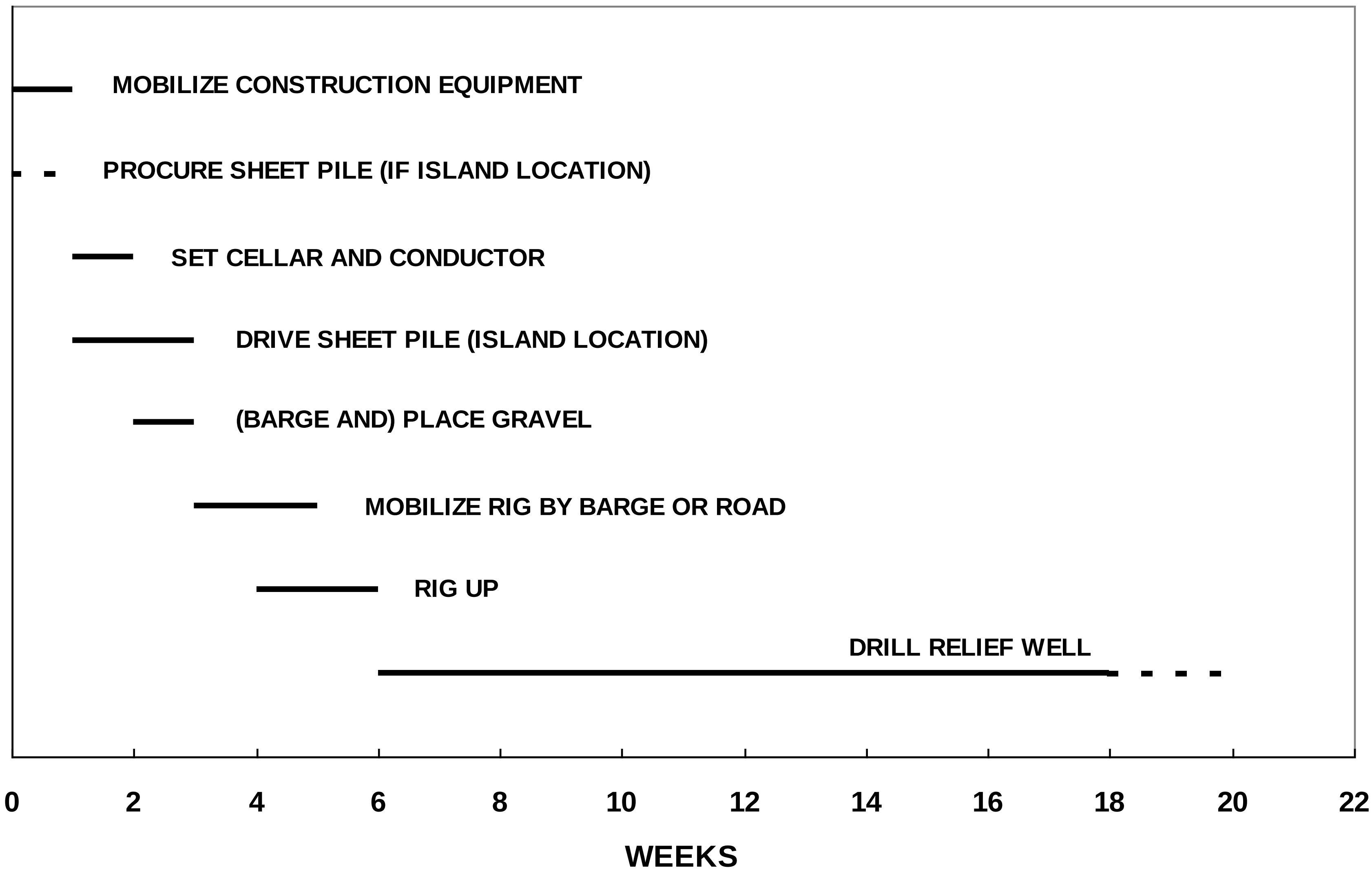


FIGURE 1-5E
SUMMER MOBILIZATION FOR RELIEF WELL



mud/gas/condensate mixture from the wellbore. If the well does not die, the simulation is repeated with heavier mud and/or higher pump rate until the well does die. If the well still cannot be killed (with an acceptable surface injection pressure), larger-bore tubulars in the relief well are usually required. In the event of a real blowout, the simulations would be refined to include reductions in pump rate, and perhaps density, to develop a pumping schedule that ultimately leads to a static well kill with the pumps off and with no losses at the casing shoe.

Summary

While plans call for surface intervention techniques to be employed in the event of a blowout, ExxonMobil is nevertheless fully prepared to drill a relief well at Point Thomson. The time required to bring a blowing well under control using a relief well will likely be significant, due principally to the depths of the blowing/relief wells and to the potential need to mobilize a relief well drilling rig from Deadhorse.

Permits

In the event of a well blowout, federal, state, and North Slope Borough (NSB) permits might be required to support the response effort. The permits would authorize the construction of gravel and offshore or onshore support facilities (e.g., ice and gravel staging pads, temporary storage areas, and temporary water use). As part of overall North Slope oil spill preparedness, ACS holds a series of permits authorizing a variety of cleanup-related activities, including bird and mammal hazing, and mammal stabilization.

ACS Tactics A-3 and W-1

1.6.4 Discharge Tracking [18 AAC 75.425(e)(1)(F)(iv)]

Discharge tracking is discussed in Section 1.6.14 and in the ACS *Technical Manual*.

ACS Tactics T-1 through T-7

1.6.5 Protection of Sensitive Areas [18 AAC 75.425(e)(1)(F)(v)]

Environmentally sensitive areas and areas of public concern include cultural resource sites, public use areas, Native allotments, and bird nesting areas. Initial strategies for protection and cleanup of these areas will be determined based on the agency priorities and data in the ACS *Technical Manual, Volume 2, Map Atlas*. Each open water, nearshore, and offshore marine area from Mikkelsen Bay to Kaktovik is subject to some probability of oiling from potential unrecovered spills. Stream sections down-slope from the condensate export pipeline are also subject to oil spills.

ACS *Technical Manual*, *Volume 2*,

Shoreline sites marked on the maps for priority protection are based on the following criteria:

- Relative value as wildlife habitat or as cultural resource, subject to confirmation by resource agencies;
- Distance from a potential oil spill, as a qualitative index of probability of oiling; and
- Practicality of protection measures, to be determined by spill responders at the time of the response.

As a spill response progresses, priorities may change based on seasonal variations and assessments conducted at the time of the spill. For incident-specific applicability, see Section 1.6.14.

ACS Tactic W-6

1.6.6 Containment and Control Strategies [18 AAC 75.425(e)(1)(F)(vi)]

ACS Tactics C-1 through C-16

Containment and control strategies are discussed in Section 1.6.14 and in the ACS *Technical Manual*.

1.6.7 Recovery Strategies [18 AAC 75.425(e)(1)(F)(vii)]

ACS Tactics R-1 through R-31

Recovery strategies are discussed in Section 1.6.14 and in the ACS *Technical Manual.*

1.6.8 Lightering, Transfer, and Storage of Oil from Tanks [18 AAC 75.425(e)(1)(F)(viii)]

ACS Tactics R-22 through R-25, R-27, and R-28

Incident-specific applicability of lightering, transfer, and storage is discussed in Section 1.6.14. ACS *Technical Manual* Tactics R-22 through R-25, R-27, and R-28 describe the detailed operational and resource requirements associated with offloading operations.

1.6.9 Transfer and Storage Strategies [18 AAC 75.425(e)(1)(F)(ix)]

ACS Tactics R-6, R-7, R-10, R-11, R-15 through R-20, R-22 through R-24, R-28, R-30, and R-31

Transfer and storage strategies are discussed in Section 1.6.14 and in the ACS *Technical Manual.*

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

ACS Tactics D-1 through D-5

The method of disposal for oil and contaminated materials from spill recovery operations, or for oily waste from normal operations, must be approved by state and federal agencies. At the time of the spill, the Operations Section Chief, in consultation with the SHE Lead, would determine a reuse, recycle, or disposal method best suited to the state of the oil, the degree of contamination of recovered debris, and the logistics involved. Application for agency approvals would be completed before the method of disposal is used. An initial determination would be made regarding the classification of the waste as exempt, hazardous, or non-hazardous. This classification may be made on a case-by-case basis. The SHE Lead will provide assistance in determining the classification, should the status of the waste material be in question. In general, the following guidelines apply:

- Spilled material will be re-used or recycled when possible.
- Spills from the DOT-regulated export oil pipeline are non-exempt and must be tested to determine whether the material to be disposed of is hazardous.
- Spills from production well lines and multi-phase flowlines are exempt and therefore non-hazardous.
- Spilled material that comes out of a well, either during drilling or workover operations, is exempt and therefore non-hazardous. Material spilled during drilling or workover operations that did not come out of a well is non-exempt and must be tested to determine whether the material to be disposed of is hazardous.
- Spills that occur from filling a tank (e.g., vehicle, storage, etc.) are non-exempt, even though they may occur on a well pad. They must be tested to determine whether the material to be disposed of is hazardous.

The preferred method for handling recovered liquid oil is disposal in the Point Thomson disposal well. The preferred option for recovered diesel is reuse (e.g., as freeze protection during drilling operations). In this case, the diesel will be stored on-site. If the diesel is not suitable for freeze protection, it will be tested to determine if it is hazardous. If hazardous, it will be stored in drums on-site until it can be shipped to an approved hazardous waste disposal facility. If non-hazardous, it may be injected in the Point Thomson disposal well.

ACS Tactic D-4

Contaminated gravel will be temporarily stored on-site with pre-approval from ADEC for the temporary storage of oily waste associated with response activities. The materials may be transported later by truck over ice road or by vessel to Deadhorse for treatment. Alternatively, contaminated gravel may be remediated or disposed of at the PTU, e.g., by washing, incineration, bioremediation, or injection in the Class I disposal well.

Other solid waste may be incinerated on-site or stored for later transport to Prudhoe Bay for disposal. Point Thomson will have two incinerators, each with a capacity of 300 pounds per hour. One of the incinerators will operate while the other incinerator is cooled, cleaned, and loaded. Consequently, even with two incinerators, the cumulative waste incineration capacity will be 300 pounds per hour. The incinerators will be designed and operated in compliance with the Incinerator Emissions Standards, outlined in 18 AAC 50.050. A percentage of the waste handled by the incinerators can be oily waste. Non-combustible solid waste and the majority of oily waste will be stored for later transport to Prudhoe Bay for disposal.

Liquids recovered from a large oil spill are either liquid oil or oil mixed with water, snow, or ice. Oil in excess of immediate processing capacity will be stored in tanks. Sources of tankage include:

- Process waste collection vessel at Point Thomson,
- Spill response equipment at Point Thomson,
- ACS spill response equipment located in Deadhorse, and
- North Slope contractors and Mutual Aid partners.

Specific types and capacities of temporary storage are described in the ACS *Technical Manual*. Additional sources of temporary storage tanks include oil companies and numerous service companies in the North Slope area. These storage tanks include 500 bbl Tiger tanks and 200 to 300 bbl vacuum trucks. Mobile tankage is estimated at 20,000 bbl in the North Slope area.

ACS Tactics D-1 through D-5

Storage of cleanup materials is described in the ACS *Technical Manual*.

1.6.11 Wildlife Protection [18 AAC 75.425(e)(1)(F)(xi)]

ACS Tactics W-1 through W-6

Wildlife protection strategies are discussed in the ACS *Technical Manual*.

1.6.12 Shoreline Cleanup [18 AAC 75.425(e)(1)(F)(xii)]

ACS Tactics SH-1 through SH-12

Shoreline cleanup strategies are discussed in ACS *Technical Manual*.

1.6.13 Response Planning Standards [18 AAC 75.430]

Well Blowout [18 AAC 75.434]

Modeling Liquid Flow Rates

The response planning standard volume calculation involves a simulated condensate flow rate that is predicted with a computer model. The model assumes that the blowout fluids move up the annulus between a 5-inch-diameter drill string and an 8.5-inch hole and the inside diameter of 9 7/8-inch casing.

The blowout modeling computer program predicts the flow of hydrocarbons from the subsurface reservoir into and up the wellbore that routes them to the surface. Because blowouts do not occur instantaneously, but over timescales that vary from several minutes to several days, the computer models calculate the changes in pressures, flow rates, fluid densities and wellbore contents as these quantities change over time. The pressures and fluid characteristics vary with distance between the reservoir and the Earth's surface.

The simulation begins by specifying the initial conditions in the reservoir and in the wellbore. Fluids in the reservoir are typically assumed to be in an equilibrium state; in a sense they are pressurized and waiting to be let out of the reservoir. In normal drilling operations, the wellbore usually contains drilling “mud,” a special high-density mixture of solids and fluids. One function of the mud is to exert a downward force that keeps the hydrocarbons confined to the reservoir. In more technical terms, the density of the mud is specifically chosen so that the hydrostatic pressure it exerts is greater than the reservoir pressure, thereby preventing the well from flowing. But to initiate flow in the simulated blowouts, the density of the mud is set at an artificially low and insufficient value in order to simulate a pressure imbalance that becomes the driving force for further flow.

Well-established mathematical equations in the blowout simulator computer program describe how fluids in the reservoir move when they are subjected to differences in pressure. The flow rates of the hydrocarbons through the reservoir depend on the properties of both the rock and the fluids. Important formation parameters include the permeability, which is a measure of the ease with which fluids move through the tortuous and interconnected pore spaces of the reservoir rock and the reservoir thickness. The relatively high permeability (measured in units of millidarcies) and thickness of the Thomson Sand formation produce high flow rates in both controlled and uncontrolled flow situations; indeed, the commerciality of the project is due in part to these very properties of the prolific Thomson Sand. Similarly, the low viscosities of the gas and condensate and the high initial reservoir pressure also contribute to high well productivity.

In addition to these fundamental elements of flow in the reservoir, the mathematical model also considers factors like turbulent flow and the fact that the wellbore may be directionally drilled through the reservoir or may only partially penetrate a fraction of the entire reservoir thickness. As simulated time advances and more reservoir fluids are produced, pressures near and at base of the wellbore decline. The model calculates the time-dependent bottom-hole pressure, an important quantity because it is the motive force pushing the fluids up the wellbore to the surface.

The flow of liquids (both mud and condensate) and gases in the wellbore is also an integral part of the blowout simulation. Equations that describe the movement of these fluids are solved repeatedly as the simulation steps forward in time, thereby continuously updating where the fluids are, how fast they are moving, and how pressures throughout the wellbore vary with time. As previously noted, the wellbore contains only mud initially; moreover, the pressure at the top of the well is due only to the atmosphere, and the bottom-hole pressure is due principally to the weight of the column of drilling mud. The flow of hydrocarbons from the reservoir eventually displaces all of the mud from the wellbore, and the fluid exiting the wellbore changes from being exclusively mud to a mixture of gas and condensate. The simulated well is blowing out at that point. The gas and condensate flow rates decline gradually over time as the reservoir is depleted, and pressures in the formation near the wellbore decrease.

The mathematical description of wellbore hydraulics is quite complex. The simulation must account for physically diverse phenomena: gravity that counters the upward direction reservoir pressure forces the fluids to flow, the interactions between the liquid and vapor phases, and pressure losses associated with friction and the acceleration of fluids to near-supersonic velocities as they flow toward the Earth's surface. In addition, the conduit for flow is geometrically complicated. Typically, an inclined annulus consists of either the borehole wall or steel casing in the well on the outside and the varying diameters of the drill string on the inside. Finally, the rates and pressure of the fluids entering the wellbore must match exactly the rates and pressures of the fluids exiting the formation, while the rates and pressure at the top of the wellbore must match the requirements for flow from an orifice to the atmosphere.

With these special-purpose blowout simulation methods, ExxonMobil determined the expected flow rates that would be encountered in the unlikely event of a Point Thomson blowout. The simulations used site-specific reservoir and fluid data and the specifications of the wellbores planned for development of several blowout scenarios at Point Thomson.

Voluntary ignition of a blowout is ExxonMobil's preferred alternative for ensuring the safety of personnel and protection of the environment from large quantities of liquid condensate at Point Thomson. The air pollutant of most concern from burning oil or condensate is particulate matter, in this case, non-combusted condensate as soot. ExxonMobil used the SCREEN3 model to determine if particulate matter emissions from a burning blowout at Point Thomson have the potential to create exceedences of the national standards (EPA, 1995a). It is anticipated that any condensate blowout at Point Thomson will behave much like an industrial flare, which is designed for efficient combustion. Combustion of a Point Thomson blowout will be very efficient because the high velocity of the high-heating-value reservoir fluids exiting the well will lead to significant air entrainment[1]. The estimated combustion efficiencies are expected to be 99 percent for the gaseous components and approximately 90 percent for the liquids. Soot emissions for air quality modeling were based on all 10 percent unburned liquid forming soot and on light smoking of the gaseous fraction (approximately 310 grams of soot per million British Thermal Units [BTUs] fired, EPA's manual for emissions estimating BTU, 1995b). That is, ExxonMobil used a conservative assumption that all unburned components of the smoke plume were particulates. Based on results using EPA's SCREEN3 model, the maximum ground-level concentration of PM_{10} (particulate matter 10 microns in diameter) is predicted to be 65.6 micrograms per cubic meter ($\mu g/m^3$), well below the 24-hour average National Ambient Air Quality Standard of 150 $\mu g/m^3$.

ExxonMobil also studied the gas/condensate plume from an unignited blowout at Point Thomson using a computer model, known as SCIPUFF (Titan, 2003), to determine the

[1] Communication with Mr. Robert Schwartz of John Zink Company.

amount and distribution of the liquid condensate that would fall to land and water. SCIPUFF is an EPA-approved model. ExxonMobil used the following assumptions for the model:

- The predictions of droplet-size distribution used are conservative for Point Thomson well blowout cases because additional droplet break-up mechanisms of flashing and supersonic mechanical break-up were ignored. Supersonic break-up (as flow can exceed the speed of sound at discharge) may produce even smaller droplet sizes due to mechanical break-up, while flashing of liquids on discharge produce smaller drops than from only mechanical break-up.
- The predictions of deposition may be conservative for Point Thomson because the evaporative properties of a less volatile component (i.e., dodecane) were used that may over-estimate deposition for more volatile compounds (e.g., octane).
- The drill pipe is still in hole (hole diameter is 8.5 inches, and drill pipe outside diameter is 5 inches).
- Flow rates are 465 million standard cubic feet per day (mmscf/d) of gas and 27,000 bbl of condensate per day for 15 days.
- The condensate characteristics are presented in Table 1-8.

TABLE 1-8
SUMMARY OF CONDENSATE CHARACTERIZATIONS FOR RELEASE TO THE ATMOSPHERE (MOLE PERCENT)

COMPONENT	PRODUCED GAS STREAM (%)	WELLHEAD LIQUID FOR BLOWOUT (290 PSIA @ 210°F (%)	LIQUID FLASHED TO 40°F AND 14.65 PSIA (%)	
N_2	0.6	0.0	0.0	**Non-Persistent Components**
CO_2	4.4	0.5	0.1	
Methane	83.8	5.3	0.4	
Ethane	4.2	0.9	0.3	
Propane	1.7	0.8	0.6	
I-Butane	0.4	0.3	0.3	
N-Butane	0.6	0.7	0.7	
I-Pentane	0.2	0.5	0.5	
N-Pentane	0.3	0.6	0.6	
C_6	0.5	3.3	3.6	
C_7	0.4	6.0	6.4	
C_8	0.4	9.0	9.6	
C_9	0.3	7.8	8.3	
C_{12}	1.1	33.7	35.9	
C_{17}	0.7	20.4	21.8	
C_{27}	0.3	8.5	9.1	**More Persistent Components**
C_{42}	0.0	1.3	1.3	
C_{65}	0.0	0.3	0.3	
C_{86+}	0.0	0.1	0.1	
Total	**~100**	**~100**	**~100**	

psia = pounds per square inch absolute
ºF = degrees Fahrenheit
N_2 = Nitrogen
$C0_2$ = Carbon dioxide
$C_\#$ = Various organic compounds

Simulated Rates

Liquid flow rate (barrels per day [bpd])[1]	27,000
Combustion efficiency (%)	90
Uncombusted condensate as soot (%)	99
Evaporation from aerial droplets (%)	25
Evaporation of condensate from water and land surface (%)	40
Duration of blowout period (days)	15

Prevention Credits

Alcohol and drug testing credit	5%
Operations training or Federal certification credit	5%
Real time bottom-hole pressure measurements credit	5%
Computer preventative maintenance system credit	5%
Formal safety analysis credit	5%
Emergency shutdown SCSSV valves	5%
Operations Integrity Management System (OIMS)	10%
Assurance of well tubular integrity	5%
On-site mud plant	5%
Overbalanced drilling confirmation technique	5%
Five-preventer BOP stack	10%

See Section 2.6.1 for a description of prevention credits claimed for the Point Thomson well blowout RPS volume.

Response Planning Standard (RPS) Volume Calculation

Initial RPS Volume, Day 1, Hours 0 to 2	=	27,000 bpd x 2 hr to ignite / 24 hr per day x (1 - 0.25) x (1 - 0.40) after aerial and surface evaporation = 1013 bbl
Adjusted RPS Volume, Day 1, Hours 0 to 2 (prior to well ignition)	=	1013 bbl x (0.95 credit x 0.95 credit x 0.95 credit x 0.95 credit x 0.95 credit x 0.95 credit x 0.90 credit x 0.95 credit x 0.95 credit x 0.95 credit x 0.90 credit] = 517 bbl
Initial RPS Volume, Day 1, Hours 2 to 24	=	(27,000 bpd x 22 hr / 24 hr x 0.10 unburned x 0.01 liquid deposition) = 24.75 bbl
Adjusted RPS Volume, Day 1, Hours 2 to 24	=	24.75 bbl x (0.95 credit x 0.95 credit x 0.95 credit x 0.95 credit x 0.95 credit x 0.95 credit x 0.90 credit x 0.95 credit x 0.95 credit x 0.95 credit x 0.90 credit) = 13 bbl
Total Adjusted RPS Volume, Day 1	=	517 bbl + 13 bbl = 530 bbl
Initial RPS, Days 2 through 15	=	14 days x (27,000 barrels of oil per day (bopd) x 0.10 unburned x 0.01 liquid deposition) = 378 bbl

[1] ExxonMobil Modeled Case 1, annulus route, drill pipe in hole.

Adjusted RPS Volume, Days 2 through 15	=	378 bbl x (0.95 credit x 0.95 credit x 0.95 credit x 0.95 credit x 0.95 credit x 0.95 credit x 0.90 credit x 0.95 credit x 0.95 credit x 0.95 credit x 0.90 credit) = 193 bbl
Day 1, Hours 2 to 24 Volume plus Days 2 through 15 Volume (after well ignition)	=	13 + 193 = 206 bbl
Total Adjusted RPS Volume (Days 1 through 15)	=	517 + 206 = 723 bbl

Condensate Export Oil Pipeline [18 AAC 75.436]

The response planning standard (RPS) volume assumes an instantaneous guillotine rupture at milepost 14.7 of the pipeline.

The location was selected based on the consideration that it is one of the most remote points of the pipeline crossing a water body. Consequently, it would be among the most challenging locations for spill responders.

The RPS volume value is calculated using the following equation from 18 AAC 75.436:

RPS Volume = (L - H) x C + FR x (TD + TSD)

Where:

L	=	pipeline length between valves
H	=	pipeline hydraulic characteristics due to terrain
C	=	pipeline capacity in bbl per linear measure
FR	=	pipeline oil flow rate in bbl per time period
TD	=	estimated time to detect a spill event
TSD	=	time to shut down the pipeline pump or system

L	=	112,992 feet (21.4 miles x 5,280 feet per mile)
H	=	107,184 feet (20.3 miles x 5,280 feet per mile)
C	=	0.145 bbl/linear foot (LF) = [((12.75-inch outside diameter – 2 x 0.28-inch wall thickness) / 2)^2 x 3.14) / 144 square inches per square foot] / 5.6 cubic feet/bbl
FR	=	69.44 bbl/minute (100,000 bbl/day / 1,440 minutes/day)
TD	=	3 minutes
TSD	=	5 minutes

Therefore:

Initial RPS Volume	=	[(112,992 feet – 107,184 feet) x (0.145 bbl/LF)] + (69 bbl/minute x 8 minutes)
	=	1,394 bbl

Adjusted RPS Volume	=	1,394 bbl x 0.95 for 5% drug and alcohol testing credit x 0.95 for 5% on-line leak detection system x 0.85 for 15% corrosion control using smart pigs x 0.40 for 60% loss from evaporation
	=	428 bbl

See Section 2.6.3 for a description of prevention credits claimed for the Point Thomson condensate export pipeline RPS volume.

Fuel Storage Tank Rupture [18 AAC 75.432]

The adjusted RPS volume for the fuel storage tank at the CPF is calculated below. None of this simulated volume would spill to open water. See Section 2.6.2 for a description of prevention credits claimed for the Point Thomson fuel storage tank rupture RPS volume.

Initial RPS Volume (capacity of the tank)	12,500 bbl
60% adjustment for secondary containment	-7,500 bbl
Subtotal	5,000 bbl
5% adjustment for alcohol and drug testing	-250 bbl
Subtotal	4,750 bbl
5% adjustment for operations training and licensing	-237.5 bbl
Subtotal	4,512 bbl
5% adjustment for on-line leak detection for tank and piping	-226 bbl
Subtotal	4,287 bbl
15% adjustment for fail-safe valve piping systems	-643 bbl
Subtotal	3,644 bbl
25% adjustment for double bottoms with leak detection	-911 bbl
Subtotal	2,733 bbl
TOTAL Adjusted RPS Volume	2,733 bbl

1.6.14 Response Scenarios [18 AAC 75.425(e)(1)(F)]

The scenarios that follow were developed in accordance with 18 AAC 75.425(e)(1)(F) and 18 AAC 75.445(d). They describe equipment, personnel, and strategies that could be used to respond to an oil spill. The scenarios are for illustration purposes only and are not performance standards or guarantees of performance. The scenarios assume conditions of the spills and responses only for the purposes of describing general procedures, strategies, tactics, and selected operational capacities.

Some details in the scenarios 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 personnel safety.

In situ burning could be used in a spill response to reduce the quantity of oil, regardless of whether a scenario illustrates *in situ* burning as a primary response option. In this plan, *in situ* burning means burning oil where it has spilled, as an oil removal technique. *In situ* burning excludes ignition of hydrocarbons in an aerial blowout plume or burning of oily waste material.

Actual responses to an oil spill event depend on personnel safety considerations, weather and other environmental conditions, agency permits, response priorities, and other factors. In any incident, considerations to ensure the safety of personnel will be given highest priority. The scenarios assume the agency on-scene coordinators and other agency officials will immediately grant any required permits.

The scenarios are generally based on information contained in the ACS *Technical Manual*, except where the information does not apply to condensate, a non-persistent material, and except that meteorological data from the Point Thomson area are used for blowout plume wind.

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The scenarios assume reduced operational hours per shift and skimming rates less than nameplate capacity to account for realistic maximum operating limitations and other down-time factors.

Some scenarios simulate use of heavy equipment, e.g., trucks and front-end loaders. 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 NSSRT.

SCENARIO CONTENTS

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SCENARIO 1

POINT THOMSON CONDENSATE EXPORT PIPELINE SPILL TO OPEN WATER

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TABLE 1-9
CONDENSATE EXPORT PIPELINE SPILL TO OPEN WATER
SCENARIO CONDITIONS

PARAMETER	PARAMETER CONDITIONS
Spill Location	Condensate export oil pipeline crossing of unnamed creek near pipeline milepost 14.7
Spill Time	August 1
Source of Spill	Guillotine break in export pipeline
Type of Spill	Instantaneous, guillotine rupture
Quantity of Oil Spilled	The RPS volume assumes an instantaneous guillotine rupture at milepost 14.7 of the pipeline. **Adjusted RPS Volume = 428 bbl**
Oil Type	Condensate
Wind Speed	20 knots
Wind Direction	Day 1: wind from SW Day 2 and beyond: wind from NE
Current	River has no significant net flow. Marine surface water flows 0.6 knots at 3 percent of wind speed.
Air Temperature	40°F
Trajectory	Condensate falls from the pipeline break into the un-named creek that enters the Beaufort Sea 2.6 miles S of Bullen Point spit. Pipeline segment drains within 6 hours. The width of the condensate plume where it reaches the creek surface, 5 feet below the pipeline, is assumed narrower than the creek width. Condensate exits the pipeline rupture at the rate of 232 barrels per hour (bph) (163 gpm; 0.363 cubic feet per second). Condensate flows down the creek into the lagoon 2 miles N at that discharge rate. In the creek and lagoon on the first day of exposure, condensate becomes reduced to 40 percent of its original volume by evaporation. Condensate on the creek moves at 0.5 mph, reaching the lagoon in 4 hours. Over the 6 hours of the discharge, most of the un-evaporated condensate strands on the creek and lagoon shoreline gravel, soil, and vegetation. Before responders reach the site, most spilled condensate reaching the 1-mile-wide lagoon strands on its shoreline or escapes into Mikkelsen Bay where it moves northeastward at a speed of 0.6 knots. When the spill is detected and the pipeline is shut down at Hour 0 of the response, the wind blows from the SW and begins to push the condensate to the NE. Within 6 hours and 45 minutes, condensate begins stranding on the western end of Challenge Island.

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TABLE 1-10
CONDENSATE EXPORT PIPELINE SPILL TO OPEN WATER
RESPONSE STRATEGY

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECH. MANUAL TACTIC
(i) Stopping Discharge at Source	When the control room detects the immediate drop in pressure in the pipeline, the flow is shut down at the Central Well Pad (CWP) pumps and at the CWP and Badami tie-in valves.	Not applicable
(ii) Preventing or Controlling Fire Hazards	Throughout the first few hours of the response, the Site Safety Officer verifies that all sources of ignition are shut down or removed from the area. The Site Safety Officer provides access zone information and determines PPE requirements. Access to the spill site is carefully controlled and the scene is secured by Security. Monitoring protocol is established by the Site Safety Officer for all work areas to ensure personnel protection.	Not applicable
(iii) Well Control Plan	Not applicable	Not applicable
(iv) Surveillance and Tracking of Oil; Forecasting Shoreline Contact Points	Aerial observation with aircraft provides real-time tracking of the leading edge of the condensate. Tracking buoys are deployed from an ACS response skiff at the creek mouth at Hour 6 of the response. The National Oceanic and Atmospheric Administration (NOAA) is requested to provide trajectories based on wind speed and direction.	T-4 T-5
(v) Exclusion Procedures	The ACS *Technical Manual Map Atlas*, Sheets 98 and 101 are consulted to determine shoreline sensitivities and priority protection sites. No priority protection sites lie in the spill trajectory. The area is monitored for birds and mammals that may be at risk from the spill.	ACS Atlas Sheets 98 and 101 W-6
(vi) Spill Containment and Control Actions **and** **(vii) Spill Recovery Procedures**	**Stream Task Force.** Teams 1, 2, and 3 each deploy an exclusion boom and skimmer downstream of the pipeline crossing at Hour 8, following 1 hour for notification and site safety characterization, 1 hour to mobe, average 3 hours to travel, and 3 hours to deploy. Teams 1 and 2 use airboats from Point Thomson to travel up the creek 2 miles to the rupture site and a downstream control site. Team 3 from Endicott or West Dock sets up the third control site downstream. The objective is to contain and recover the spilled material close to its source to minimize spreading downstream. **Marine Task Force.** A marine team with a skimming vessel, boom towing skiff, freighter airboat, mini-barge, and boom deploys at Hour 6, following 1 hour for mobilization at Point Thomson dock, 3 hours to travel from Point Thomson, and 2 hours to deploy. The team travels 15 nautical miles (NM) from Point Thomson dock and targets floating condensate in the lagoon and in eastern Mikkelsen Bay. Over 3 days of response, the derated recovery capacity exceeds the RPS volume.	C-9 (3) R-8 (3) L-6 R-17 L-6
(viii) Lightering Procedures	No on-water lightering.	
(ix) Transfer and Storage of Recovered Oil/Water; Volume-Estimating Procedure	**Marine Recovery Task Force.** Condensate recovered by the marine on-water task force is pumped into mini-barges. A shuttle boat delivers an empty mini-barge and tows a loaded mini-barge an average 15 NM to Point Thomson dock for off-loading to vacuum trucks and temporary tanks. The number and turn-around time of mini-barges transfers stored liquid at a greater rate than it is collected and, consequently, transfer does not constrain the on-water recovery rates. **Stream Task Force.** Condensate recovered from the stream channel behind the three control site booms is stored in a Fold-a-Tank at each site. From the Fold-a-Tank, the liquid is pumped to a tank on an airboat and shuttled to Point Thomson dock. Stored condensate and water are hauled by vacuum truck to the slop oil tanks. Ullage tape and Coliwasa tubes gauge liquid volumes and water cut in the mini-barges and vacuum trucks for waste manifests.	R-22 R-25 (3)

TABLE 1-10 (CONTINUED)
CONDENSATE EXPORT PIPELINE SPILL TO OPEN WATER
RESPONSE STRATEGY

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECH. MANUAL TACTIC
(x) Plans, Procedures, and Locations for Temporary Storage and Disposal	Temporary storage facilities in bermed, lined pits are established at CPF pad and at the Bullen Point landing strip for oily wastes under a plan approved by the Unified Command and ADEC. Liquid and non-liquid wastes are characterized and disposed of accordingly.	D-1, D-2, D-3, D-4
(xi) Wildlife Protection Plan	Resources at risk are primarily birds. • The wildlife protection strategy is implemented. • Wildlife hazing teams are deployed on the creek and on oiled marine shorelines. • The Wildlife Stabilization Center is made operational at Deadhorse. • As oiled wildlife is identified, capture teams are deployed to the spill scene. • Captured birds are carried by wildlife response skiff to Point Thomson, where they are flown in fixed-wing aircraft to Deadhorse for treatment.	W-1 W-2B W-5 W-3
(xii) Shoreline Cleanup Plan	Shoreline cleanup operations are initiated once the source of the condensate has been stopped, based on a plan approved by Unified Command. A shoreline assessment is conducted to understand the nature and extent of oiling. Based on shoreline assessment, priorities are established for cleanup. Cleanup techniques chosen are based on shoreline type and degree of oiling. Primary shoreline cleanup techniques would include: • Manual recovery of heavier pockets of condensate stranded along the shorelines. • Deluge of minor to moderately oiled shoreline in the river, including those areas where heavier concentrations were manually removed. • Mechanical removal at heavily oiled sites. • Natural recovery for those areas where residual staining may remain, but further recovery would cause more harm than good.	SH-1 SH-2 through SH-11 SH-5 SH-3 SH-6 SH-2

TABLE 1-11
CONDENSATE EXPORT PIPELINE SPILL TO OPEN WATER
OIL RECOVERY CAPACITY

A	B	C	D	E	F	G
SPILL RECOVERY TACTIC	**NUMBER OF SYSTEMS**	**RECOVERY SYSTEM**	**DERATED OIL RECOVERY RATE (boph)**	**MOBILIZATION, TRANSIT, AND DEPLOYMENT TIME TO SITE (hours)**	**OPERATING TIME (hours in a 24-hour shift)**	**DAILY DERATED OIL RECOVERY CAPACITY (bpd) (B x D x F)**
R-8	3	Drum/Brush	28	7	20	1,680
R-17	1	Drum/Brush	28	6	20	560

boph bbl of oil per hour

TABLE 1-12
CONDENSATE EXPORT PIPELINE SPILL TO OPEN WATER
LIQUID HANDLING CAPABILITY

A	B	H	I	J	K	L	M	N	O	P
SPILL RECOVERY TACTIC	**NUMBER OF STORAGE SYSTEMS**	**STORAGE CAPACITY DESCRIPTION**	**STORAGE CAPACITY (bbl)**	**OIL/ EMULSION AVAILABLE (bph)**	**TIME ON LOCATION BEFORE OFFLOAD NEEDED (hours) (I/J)**	**OFF-LOADING MECHANISM**	**OFF-LOADING RATE (bph)**	**TRANSIT TIME – BOTH WAYS (hours)**	**OFF-LOADING TIME (hours) (I/M)**	**OFF-LOAD AND TRANSIT TIME (hours) (N+O)**
R-8, R-25	3	Fold-a-Tank	36	203 bbl / 3 teams / (72 hr – 8 hr) = 1 bph per tank	36	R-25, Fold-a-Tank via 2-inch pump to 300-gallon tank	312[1]	6	0.1	6.1
R-17, R-22	1	Mini-Barge	237	203 / (72 hours – 6 hours) = 3.1 bph	76	R-22, to vacuum truck	158[2]	6.0	1.5	7.5

1 Assumes 312 bph cited in R-25.
2 Assumes 1.5 hours to off-load, following Assumption #23 in front of ACS *Technical Manual*.

TABLE 1-13
CONDENSATE EXPORT PIPELINE SPILL TO OPEN WATER
MAJOR EQUIPMENT EQUIVALENTS TO MEET THE RESPONSE PLANNING STANDARD

TACTIC	NO. TACTICAL UNITS	EQUIPMENT PER TACTICAL UNIT	TOTAL QUANTITY
R-8, R-25	3	Delta Boom, 300 feet	900 feet
		Fold-a-Tank, 1 each	3
		Drum/Brush, 1 each	3
		Airboat, 1 each	3
		Pump, 1 each	3
R-17, R-22	1	Skimming Vessel with built-in recovery system and storage[1]	1
		Freighter Airboat for Shuttle	1
		Shallow Water Boom Towing Skiff	1
		Boom, 500 feet	500 feet
		Mini-Barge	2

[1] This piece of equipment will be listed in the ACS *Technical Manual* when it is purchased.

TABLE 1-14
CONDENSATE EXPORT PIPELINE SPILL TO OPEN WATER
EQUIPMENT FOR SHORELINE PROTECTION

TACTIC	NO. TACTICAL UNITS	EQUIPMENT PER TACTICAL UNIT	TOTAL QUANTITY
C-15	1	Workboat, Type A, 2 each	2
		Intertidal Boom and Delta Boom	5,300 feet

TABLE 1-15
CONDENSATE EXPORT PIPELINE SPILL TO OPEN WATER
STAFFING TO OPERATE OIL RECOVERY AND TRANSFER EQUIPMENT

LABOR CATEGORY	TACTIC	NO. TACTICAL UNITS	NO. STAFF PER UNIT	NO. STAFF PER SHIFT[1]
Team Lead	C-9, R-8	3	1	3
	R-17	1	1	1
	R-25	3	1	3
Large Vessel Operator	R-17 Skim Vessel and Shuttle	1	2	2
	R-25	3	1	3
Small Vessel Operator	R-17	1	1	1
Skilled Technician	C-9, R-8	3	4	12
	R-17	1	2	2
	R-25	3	1	3
General Technician	R-17	1	2	2
	R-25	3	2	6
Total Technicians[2]	-	-	-	31

[1] The staffing schedule is shown in the column for number of staff per period. Number of staff recovering oil becomes zero after Hour 72.

[2] The total tallies the vessel operators and technicians. Team Leads operate vessels.

TABLE 1-16
CONDENSATE EXPORT PIPELINE SPILL TO OPEN WATER
STAFFING FOR SHORELINE PROTECTION

LABOR CATEGORY	TACTIC	NO. TACTICAL UNITS	NO. STAFF FOR SETUP	NO. STAFF PER UNIT	NO. STAFF PER SHIFT
Team Lead	C-15	1	1	1	1
Small Vessel Operator		1	2	2	2
Skilled Tech		1	3	1	1
Total[1]	-	-	5	3	3

[1] The total tallies the operators and technicians. Team Leads operate vessels.

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FIGURE 1-6 CONDENSATE EXPORT PIPELINE SPILL TO OPEN WATER SCENARIO VICINITY MAP

FIGURE 1-7 CONDENSATE EXPORT PIPELINE SPILL TO OPEN WATER SCENARIO

SCENARIO 2

POINT THOMSON CONDENSATE EXPORT PIPELINE SPILL DURING BREAK-UP

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TABLE 1-17
CONDENSATE EXPORT PIPELINE SPILL DURING BREAK-UP
SCENARIO CONDITIONS

PARAMETER	PARAMETER CONDITIONS
Spill Location	Condensate export oil pipeline crossing of un-named creek near pipeline milepost 14.7
Spill Time	June 1
Source of Spill	Guillotine break in condensate export pipeline
Type of Spill	Instantaneous guillotine rupture
Quantity of Oil Spilled	**Adjusted RPS Volume = 428 bbl**
Oil Type	Condensate
Wind Speed	20 knots
Wind Direction	Day 1: wind from SW Day 2 and beyond: wind from NE
Current	Stream flows 2.5 mph at peak flow. Lagoon frozen, overflood water has a wind-induced current of 0.6 knots at 3 percent of wind speed.
Air Temperature	35°F
Surface	Stream carries water and ice. Lagoon is ice-covered with overflood water accumulating near shore.
Trajectory	Condensate falls from the pipeline break into the un-named creek that enters the Beaufort Sea 2.6 miles S of Bullen Point spit. Pipeline segment drains within 6 hours. The width of the condensate plume where it reaches the creek surface, 5 feet below the pipeline, is assumed narrower than the creek width. Condensate exits the pipeline rupture at the rate of 232 bph (163 gpm; 0.363 cubic feet per second). Condensate flows down the creek into the lagoon 2 miles N at that discharge rate. Condensate on the creek moves at 2.5 mph, reaching the lagoon in 48 minutes. Lifted by the rising stream, the un-evaporated condensate moves onto the overflood waters. In the creek and lagoon estuary, on the first day of exposure, condensate becomes reduced to 40 percent of its original volume by evaporation. By Hour 7, virtually all of the condensate has left the river and entered the lagoon with overflood waters. The floating condensate reaching the 1-mile-wide estuary is pushed by the prevailing SW wind towards the eastern shoreline of the estuary. One day after the spill is reported, the wind shifts to the NE and begins to push condensate in the lagoon estuary towards the SW shoreline.

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TABLE 1-18
CONDENSATE EXPORT PIPELINE SPILL DURING BREAK-UP
RESPONSE STRATEGY

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECH. MANUAL TACTIC
(i) Stopping Discharge at Source	When the control room detects the immediate drop in pressure in the pipeline, the flow is shut down at the CWP pumps and at the CWP and Badami valves. The pipeline is completely shut down in 8 minutes.	Not applicable
(ii) Preventing or Controlling Fire Hazards	Throughout the first few hours of the response, the Site Safety Officer verifies that all sources of ignition are shut down or removed from the area. The Site Safety Officer provides access zone information and determines PPE requirements. Access to the spill site is carefully controlled and the scene is secured by Security. Monitoring protocol is established by the Site Safety Officer for all work areas to ensure personnel protection.	S-1 through S-6
(iii) Well Control Plan	Not applicable	Not applicable
(iv) Surveillance and Tracking of Oil; Forecasting Shoreline Contact Points	Aerial observation with aircraft provides real-time tracking of the leading edge of the oil. Tracking buoys are deployed from an ACS airboat at the creek mouth at Hour 6 of the response.	T-4
(v) Exclusion Procedures	Potential impact areas and priority protection sites are identified with slick trajectory calculation, *ACS Technical Manual, Volume 2, Map Atlas* maps, and Alaska Regional Response Team's (ARRT's) *North Slope Sub-Area Plan Areas of Major Concern*. No priority protection sites are identified within the area of impact. A Shoreline Task Force member helps direct response workers away from cultural sites, based on a shoreline cleanup plan approved by the State Historic Preservation Officer and the Unified Command. A forward staging area is set up at the western end of the Bullen Point airstrip.	L-2
(vi) Spill Containment and Control Actions **and** **(vii) Spill Recovery Procedures**	**Stream Task Force.** High and fluctuating stream levels, moving ice, and high-stream flow speeds make mechanical containment and recovery infeasible within the stream. The riverbanks are still ice-covered and virtually all of the condensate enters the lagoon within 7 hours of the rupture. **Marine Task Force.** A marine team with a 30-foot freighter airboat and mounted 300-gallon DOT tank, and two 20-foot airboats, skimmer, and boom begins recovery at Hour 6, following 1 hour for mobilization at Point Thomson dock, 3 hours to travel from Point Thomson, and 2 hours to deploy. The freighter airboat also mobilizes five 1,500-gallon Fold-a-Tanks from the CWP and Western Exploration Pad at Point Thomson. The team travels 15 NM from Point Thomson dock and targets floating condensate in the overflood water in the lagoon. A second freighter airboat with a mounted 300-gallon DOT tank mobilized from Endicott deploys at Hour 4 and travels 30 NM in 6 hours to arrive on-site at Hour 10. A 10,000-gallon bladder tank stored at the Point Thomson Exploration Pad is assembled at the west end of the Bullen Point airstrip. The combined capacity of the Fold-a-Tanks and the 10,000-gallon bladder tank is 17,500 gallons, or 416 bbl. Over 3 days of response, the derated recovery capacity and storage exceeds the RPS volume.	L-7 R-25 R-17 L-6
(viii) Lightering Procedures	No lightering is anticipated.	
(ix) Transfer and Storage of Recovered Oil/Water; Volume-Estimating Procedure	**Marine Recovery Task Force.** Condensate recovered by the marine on-water task force is pumped into the 300-gallon DOT tanks on the two freighter airboats. The airboats haul recovered condensate to the eastern shore of the lagoon where five 1,500-gallon Fold-a-Tanks and a 10,000-gallon bladder tank are erected on the Bullen Point landing strip. The freighters are offloaded with a 2-inch trash pump. Ullage tape and Coliwasa tubes gauge liquid volumes and water cut in the tanks.	R-25

TABLE 1-18 (CONTINUED)
CONDENSATE EXPORT PIPELINE SPILL DURING BREAK-UP
RESPONSE STRATEGY

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECH. MANUAL TACTIC
(x) Plans, Procedures, and Locations for Temporary Storage and Disposal	Temporary storage facilities in bermed, lined pits are established at CPF pad and at the Bullen Point landing strip for oily wastes under a plan approved by the Unified Command and ADEC. Liquid and non-liquid wastes are characterized and disposed of accordingly.	D-1, D-2, D-3, D-4
(xi) Wildlife Protection Plan	Resources at risk are primarily birds. • The wildlife protection strategy is implemented. • Wildlife hazing teams are deployed on the creek and on oiled marine shorelines if the shorelines are ice-free. • The Wildlife Stabilization Center is made operational at Deadhorse. • As oiled wildlife are identified, capture teams are deployed to the spill scene. • Captured birds are carried by wildlife response skiff to Point Thomson, where they are flown in fixed-wing aircraft to Deadhorse for treatment.	W-1 W-2B W-5 W-3
(xii) Shoreline Cleanup Plan	Shoreline cleanup operations are initiated once the source of the oil has been stopped, based on a plan approved by Unified Command. A shoreline assessment is conducted to understand the nature and extent of oiling. Based on shoreline assessment, priorities are established for cleanup. Cleanup techniques chosen are based on shoreline type and degree of oiling. Primary shoreline cleanup techniques would include: • Manual recovery of heavier pockets of oil stranded along the shorelines • Deluge of minor to moderately oiled shoreline in the river, including those areas where heavier concentrations were manually removed • Mechanical removal at heavily oiled sites • Natural recovery for those areas where residual staining may remain, but further recovery would cause more harm than good	SH-1 SH-2 through SH-11 SH-5 SH-3 SH-6 SH-2

TABLE 1-19
CONDENSATE EXPORT PIPELINE SPILL DURING BREAK-UP
OIL RECOVERY CAPACITY

A	B	C	D	E	F	G
SPILL RECOVERY TACTIC	**NUMBER OF SYSTEMS**	**RECOVERY SYSTEM**	**DERATED OIL RECOVERY RATE (boph)**	**MOBILIZATION, TRANSIT AND DEPLOYMENT TIME TO SITE (hours)**	**OPERATING TIME (hours in a 24-hour shift)**	**DAILY DERATED OIL RECOVERY CAPACITY (bpd) (B x D x F)**
R-17	1	Drum/Brush	28	6	20	560

TABLE 1-20
CONDENSATE EXPORT PIPELINE SPILL DURING BREAK-UP
LIQUID HANDLING CAPABILITY

A	B	H	I	J	K	L	M	N	O	P
SPILL RECOVERY TACTIC	**NUMBER OF STORAGE SYSTEMS**	**STORAGE CAPACITY DESCRIPTION**	**STORAGE CAPACITY (bbl)**	**OIL/ EMULSION AVAILABLE (bph)**	**TIME ON LOCATION BEFORE OFFLOAD NEEDED (hours) (I/J)**	**OFF-LOADING MECHANISM**	**OFF-LOADING RATE (bph)[1]**	**TRANSIT TIME – BOTH WAYS (hours)**	**OFF-LOADING TIME (hours) (I/M)**	**OFF-LOAD AND TRANSIT TIME (hours) (N+O)**
R-17	2	300-gallon DOT tanks	7.1 / tank	428 / 2 tanks (72 hr – 6 hr) = 3.2 bph per tank	2	R-25	312	0.5	0.05	0.55

1 Assumes 2-inch Trash pump rated at 312 bph

TABLE 1-21
CONDENSATE EXPORT PIPELINE SPILL DURING BREAK-UP
MAJOR EQUIPMENT EQUIVALENTS TO MEET THE RESPONSE PLANNING STANDARD

TACTIC	NO. TACTICAL UNITS	EQUIPMENT PER TACTICAL UNIT	TOTAL QUANTITY
R-17	1	Skimmer	1
		Airboat to tow boom and operate skimmer and pump	1
		Boom-Towing Airboat	1
		Boom	500 feet
R-25	2	Freighter Airboat (acts as shuttle for R-17)	2
		300-gallon DOT tank	2

TABLE 1-22
CONDENSATE EXPORT PIPELINE SPILL DURING BREAK-UP
STAFFING TO OPERATE OIL RECOVERY AND TRANSFER EQUIPMENT

LABOR CATEGORY	TACTIC	NO. TACTICAL UNITS	NO. STAFF PER UNIT	NO. STAFF PER SHIFT[1]
Team Lead	R-17	1	1	1
	R-25	2	1	2
Large Vessel Operator	R-17	1	1	1
	R-25	2	1	2
Small Vessel Operator	R-17	1	1	1
Skilled Technician	R-17	1	2	2
	R-25	2	1	2
General Technician	R-17	1	2	2
	R-25	2	2	4
Total Technicians[2]	-	-	-	14

1 The staffing schedule is shown in the column for number of staff per period. Number of staff recovering oil becomes zero after Hour 72.

2 The total tallies the vessel operators and technicians. Team Leads operate vessels.

FIGURE 1-8 CONDENSATE EXPORT PIPELINE SPILL DURING BREAK-UP SCENARIO VICINITY MAP

FIGURE 1-9 CONDENSATE EXPORT PIPELINE SPILL DURING BREAK-UP SCENARIO

SCENARIO 3

POINT THOMSON DIESEL TANK RUPTURE DURING SUMMER

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TABLE 1-23
DIESEL TANK RUPTURE DURING SUMMER
SCENARIO CONDITIONS

PARAMETER	PARAMETER CONDITIONS
Spill Location	Diesel fuel storage tank at CPF
Date	Summer
Duration	Instantaneous
Type of Spill	Catastrophic tank rupture
Emulsification Factor (Applicable to oil that reaches open water, for storage purposes)	Not applicable
Quantity of Oil Spilled	**Adjusted RPS Volume = 2,733 bbl** **Volume retained in gravel** = (3,844 square feet gravel x 0.5 gallons per square foot) / 42 gallons per bbl) = 45 bbl in gravel **Volume retained in tundra** = 1. Area in which off-pad diesel will be retained = (Adjusted RPS Volume) – (Volume retained in gravel) x (42 gallons per bbl) / (retention rate of 3 gallons per square foot) = 37,632 square feet or an approximate 194-foot by 194-foot area. 2. One pond and half the area of another small pond falls within this off-pad zone; the pond areas are subtracted from the total affected tundra area = (37,632 square feet) – (13,125 square feet of pond one) – [(7,850 square feet of pond two) / 2] = 20,582 square feet. 3. Convert the affected tundra area (less the area of the ponds) into bbl, assuming diesel retention rate of 3 gallons / square foot = 16,760 square feet x (3 gallons / square foot) / 42 gallons per bbl = 1,470 bbl in tundra. **Volume entering ponds** = (Adjusted RPS Volume – Volume retained in gravel – Volume retained in tundra) = (2,733 bbl – 45 bbl – 1,470 bbl) = 1,218 bbl on ponds.
Oil Type	Arctic diesel
Wind Speed	20 knots
Wind Direction	Day 1: wind from the SW Day 2+: wind from the NE
Current	Not applicable
Air Temperature	40°F
Trajectory	The majority of the diesel is contained within the tank's interstitial space. Approximately 1,890 gallons (45 bbl) are retained in the 62-foot x 62-foot gravel area crossed by the spilled diesel between the tank farm and the edge of the pad. Approximately 61,740 gallons (1,470 bbl) are retained in the 194-foot by 194-foot area of tundra over which the diesel flows. The remaining diesel enters one pond just off the pad and also impacts the east side of a second small pond west of the pad at the same rate the tundra retains the diesel (tundra retains at 3 gallons per square foot). Immediately the wind blows the diesel to the NE shore of the ponds. For the purposes of the scenario, recovery rates and stored volumes are assumed un-affected by evaporation losses or emulsification.

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TABLE 1-24
DIESEL TANK RUPTURE DURING SUMMER
RESPONSE STRATEGY

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECH. MANUAL TACTIC
(i) Stopping Discharge at Source	To prevent further diesel from entering the tank, the loading line valve is closed and the pump is tagged and locked out.	Not applicable
(ii) Preventing or Controlling Fire Hazards	• The supervisor immediately shuts down nearby ignition sources. • 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. • The Site Safety Officer provides access zone information and determines PPE requirements. Access to the spill site is controlled and the scene is secured by Security. Monitoring protocol is established by the Site Safety Officer for work areas to ensure personnel protection.	S-1 through S-6
(iii) Well Control Plan	Not applicable	
(iv) Surveillance and Tracking of Oil	A survey crew delineates the spill-affected area at CPF and vicinity. An aircraft records infrared readings and visual observations of the diesel.	T-2
(v) Exclusion Procedures	The ACS *Technical Manual*, *Volume 2, Map Atlas*, Sheet 103, is consulted to determine shoreline sensitivities and priority protection sites. No priority protection sites lie in the spill trajectory. The area is monitored for birds and mammals that may be at risk from the spill.	ACS Atlas Map 103 W-6
(vi) Spill Containment and Control Actions **and** **(vii) Spill Recovery Procedures**	**CPF and Tundra Task Force** • A staging area and field command post are set up at the CPF in the parking area located east of Building 201. • After the decontamination area is set up, Team 1 places shoreseal boom and sorbent boom on the perimeter of the contaminated tundra to deflect and contain diesel. • Team 1 also constructs gravel berms on the pad to ensure that the diesel remains trapped in the immediate areas and depressions. • Team 2 cleans the tundra and gravel. Crews flush low-pressure water over the tundra, moving diesel down to collection areas where it is recovered with vacuum truck hoses and sorbent material. Vacuum trucks collect from a position near the edge of the pad, with Manta Ray skimmer heads attached to intake hoses. • After liquids are removed, grid sampling indicates the depth of gravel penetration, and Team 3 excavates the contaminated gravel. The contaminated gravel is transported to a lined containment area south of Central Storage and stored for later handling. • Contaminated vegetation is left in place. Some is burned to reduce re-oiling of adjacent habitat. **Pond Task Force** • Containment boom is deployed at the eastern shore of the ponds to contain diesel being flushed from the tundra by Team 2. • Diesel is recovered from the boomed areas with a vacuum truck and Manta Ray skimmer. The pond task force recovery effort begins once the on-site equipment is mobilized to the pond (at Hour 1). The pond and tundra recovery teams have the ability to recover diesel at the de-rated capacity of 27 bph through Hour 72, a volume greater than the adjusted RPS volume portion entering the ponds. The vacuum trucks are stationed near the edge of the pad, with a 200-foot hose that reaches both impacted ponds and tundra.	L-2 C-4 R-4, R-6 R-26 B-1, B-2 C-5 R-6
(viii) Lightering Procedures	Not applicable	Not applicable

TABLE 1-24 (CONTINUED)
DIESEL TANK RUPTURE DURING SUMMER
RESPONSE STRATEGY

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECH. MANUAL TACTIC
(ix) Transfer and Storage of Recovered Oil/Water; Volume-Estimating Procedure	• Recovered diesel and water are hauled by vacuum truck across the pad to the facility's liquid process tanks for processing. Processed liquids are manifested. Oily sorbents are hauled by ATV on plywood paths to the pad. • Diesel volume in solids is estimated with grab samples. • The amount of diesel contained in 3,844 square feet of gravel pad is 45 bbl. At the rate of 8 cubic yards of gravel per bbl, 360 cubic yards of oily gravel are stockpiled for treatment.	D-1 R-6 R-5
(x) Plans, Procedures, and Locations for Temporary Storage and Disposal	• Oily liquids are recycled in the processing facility. • 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 treated under a contaminated soil stockpile treatment plan approved by ADEC.	D-1 D-2 D-3 D-4
(xi) Wildlife Protection Plan	• The wildlife protection strategy is implemented. • A bird-hazing team deploys passive hazing devices at the ponds beginning on the first shift. • The Wildlife Stabilization Center is made operational in Deadhorse. No oiled animals are encountered.	W-1 W-2B W-5
(xii) Shoreline and Tundra Cleanup	• The shoreline is cleaned up to the satisfaction of ADEC in the shortest possible time with teams of shoreline cleanup crews and equipment. Oily waste is hauled to a controlled and lined collection area on the pad, south of Central Storage. • Heavier pockets of stranded diesel are collected manually. • Minor to moderately oiled areas are deluged to recover diesel.	SH-1 SH-5 SH-3

TABLE 1-26
DIESEL TANK RUPTURE DURING SUMMER
OIL RECOVERY CAPACITY

A	B	C	D	E	F	G
SPILL RECOVERY TACTIC	NUMBER OF SYSTEMS	RECOVERY SYSTEM	DERATED OIL RECOVERY RATE (boph)	MOBILIZATION, TRANSIT, AND DEPLOYMENT TIME TO SITE (hours)	OPERATING TIME (hours in a 24-hour shift)	DAILY DERATED OIL RECOVERY CAPACITY (bpd) (B x D x F)
R-6	2	Vacuum Truck with Manta Ray Skimmer	27	1.5	16[1]	864

[1] Truck operates 20 hours per day, but 16 hours per day are spent recovering and 4 hours per day are needed for offloading.

TABLE 1-27
DIESEL TANK RUPTURE DURING SUMMER
LIQUID HANDLING CAPABILITY

A	B	H	I	J	K	L	M	N	O	P
SPILL RECOVERY TACTIC	NUMBER OF STORAGE SYSTEMS	STORAGE CAPACITY DESCRIPTION	STORAGE CAPACITY (bbl)	OIL/EMULSION AVAILABLE (bph)	TIME ON LOCATION BEFORE OFFLOAD NEEDED (hours) (I/J)	OFFLOADING MECHANISM	OFF-LOADING RATE (bph)	TRANSIT TIME – BOTH WAYS (hours)	OFF-LOADING TIME (hours) (I/M)	OFFLOAD AND TRANSIT TIME (hours) (N+O)
R-6	2	Vacuum Truck	100 each	27[1]	3.7[2]	Vacuum truck	200	0.5	0.5	1

[1] The total volume of diesel and free water available for storage is the recovered volume of diesel using a Manta Ray. Emulsification is not a factor.
[2] Time before offload is needed assumes a maximum de-rated recovery rate of 27 bph for a Manta Ray skimmer.

TABLE 1-28
DIESEL TANK RUPTURE DURING SUMMER
MAJOR EQUIPMENT FOR RECOVERY AND TRANSFER

TACTIC	NO. TACTICAL UNITS	EQUIPMENT PER TACTICAL UNIT	TOTAL QUANTITY
R-4	1	Fold-a-Tank	3
		Trash Pump	1
		Suction and Discharge Hose	variable
		Shore Seal Boom (1000 feet)	1000 feet
R-6	2	Vacuum Truck	2
		Manta Ray Skimmer Head	2
R-26	1	Front-end Loader	1

TABLE 1-29
DIESEL TANK RUPTURE DURING SUMMER
STAFFING TO OPERATE OIL RECOVERY AND TRANSFER EQUIPMENT

LABOR CATEGORY	TACTIC	NO. TACTICAL UNITS	NO. STAFF PER UNIT	NO. STAFF PER SHIFT[1]
Team Lead	R-4	1	1	1
	R-6	2	1	2
Skilled Technician	R-4	1	1	1
	R-6	2	2	4
General Technician	R-4	1	1	1
	R-6	2	1	2
Equipment Operators	R-6	2	1	2
	R-26	1	1	1
Total Technicians and Laborers[2]	-	-	-	8

1 The staffing schedule is shown in the column for number of staff per period. Number of staff recovering oil becomes zero after Hour 72.

2 The total tallies the technicians and laborers. Team Leads are Skilled Technicians.

FIGURE 1-10 DIESEL TANK RUPTURE DURING SUMMER VICINITY MAP

FIGURE 1-11 DIESEL TANK RUPTURE DURING SUMMER

SCENARIO 4

POINT THOMSON DIESEL TANK RUPTURE DURING FREEZE-UP

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TABLE 1-30
DIESEL TANK RUPTURE DURING FREEZE-UP
SCENARIO CONDITIONS

PARAMETER	PARAMETER CONDITIONS
Spill Location	Diesel fuel storage tank at the CPF
Date	October
Duration	Instantaneous
Type of Spill	Catastrophic tank rupture
Emulsification Factor (Applicable to oil that reaches open water, for storage purposes)	Not applicable
Quantity of Oil Spilled	**Adjusted RPS Volume = 2,733** **Volume retained in gravel** = (3,844 square feet gravel x 0.5 gallons per square foot) / 42 gallons per bbl) = 45 bbl in gravel **Volume retained in tundra snow** = 1. Area in which off-pad diesel will be retained = (Adjusted RPS Volume) - (Volume retained in gravel) x (42 gallons per bbl) / (Tactic R-3 retention rate of 3.7 gallons per cubic foot) = 30,512 cubic feet; with diesel spreading in the top 6 inches of snow = (30,512 cubic feet volume of affected snow) / (0.5 foot) = 61,025 square feet or a 250-foot by 250-foot area. 2. Two ponds fall within this off-pad zone; the pond areas are subtracted from the total affected tundra area = (61,025 square feet) – (13,125 square feet of pond one) – (7,850 square feet of pond two) = 40,050 square feet; convert to cubic feet of snow at a 6-inch depth = (40,050 square feet x 0.5 foot) = 20,025 cubic feet. 3. Convert the affect tundra area (less the area of the ponds) into bbl, assuming diesel retention rate of 3.7 gallons per cubic foot = (20,025 cubic feet) x (3.7 gallons per cubic foot) / (42 gallons per bbl) = 1,764 bbl in tundra snow. **Volume retained by pond snow and ice** = (Adjusted RPS Volume – Volume retained in gravel – Volume retained in tundra) = (2,733 bbl – 45 bbl – 1,764 bbl) = 924 bbl on pond snow and ice.
Oil Type	Arctic diesel
Wind Speed	20 knots
Wind Direction	Day 1: wind from the SW Day 2+: wind from the NE
Current	Not applicable
Air Temperature	14°F
Trajectory	The majority of the diesel is contained within the tank's interstitial space. Approximately 1,890 gallons (45 bbl) are retained in the 62-foot by 62-foot gravel area crossed by the spilled diesel between the tank farm and the edge of the pad. Approximately 74,088 gallons (1,764 bbl) are retained in the 250-foot by 250-foot area of snow-covered tundra and ponds over which the diesel flows. A portion of the diesel encounters one pond just off the pad and also impacts a second small pond west of the pad at the same rate the tundra snow retains the diesel (tundra snow retains the diesel at 3.7 gallons per cubic foot; see Tactic R-3). Diesel is retained in the snow to a maximum depth of 3 inches. Immediately, the wind blows any free diesel to the NE icy shore of the ponds where it is contained among broken ice chunks. As the ponds freeze, diesel becomes embedded in the ice and does not weather. For the purposes of the scenario, recovery rates and stored volumes are assumed un-affected by evaporation losses or emulsification.

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TABLE 1-31
DIESEL TANK RUPTURE DURING FREEZE-UP
RESPONSE STRATEGY

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECH. MANUAL TACTIC
(i) Stopping Discharge at Source	To prevent further diesel from entering the tank, the loading line valve is closed and the pump is tagged and locked out.	Not applicable
(ii) Preventing or Controlling Fire Hazards	• The Supervisor immediately shuts down nearby ignition sources. • 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. • The Site Safety Officer provides access zone information and determines PPE requirements. Access to the spill site is controlled and the scene is secured by Security. Monitoring protocol is established by the Site Safety Officer for work areas to ensure personnel protection.	S-1 through S-6
(iii) Well Control Plan	Not applicable	
(iv) Surveillance and Tracking of Oil	The extent of the diesel is marked on the snow and ice so that it can be found if subsequent snowfall or drifting covers the spill.	T-1
(v) Exclusion Procedures	The ACS *Technical Manual* is consulted to determine shoreline sensitivities and priority protection sites. No priority protection sites lie in the spill trajectory. The area is monitored for birds and mammals that may be at risk from the spill.	ACS Atlas Map 103 W-6
(vi) Spill Containment and Control Actions **and** **(vii) Spill Recovery Procedures**	**Freeze-Up:** • A staging area and field command post are set up at the CPF in the parking area located east of Building 201. • After the decontamination area is set up, a snow berm is constructed around the perimeter of the spilled diesel on the pad. Areas are shored continually and as necessary so that as much of the spill as possible is contained on the pad. • On the pad, a loader mixes snow with remaining free oil and places the mixture into a lined containment area. A vacuum truck removes remaining pools of oil from the pad. • After liquids are removed, grid sampling indicates the depth of diesel penetration in the pad. A loader and a backhoe remove up to 360 cubic yards of oiled gravel. A loader transports the gravel to a stockpile in a temporary lined and diked containment area located south of Central Storage. Gravel is stored for later handling. • Diesel is retained by snow on the tundra and frozen ponds and spreads to a maximum depth of 6 inches. A loader mechanically removes heavily oiled snow from the tundra to a depth of 6 inches. A bobcat is used for hard-to-reach areas. Lightly oiled snow is mixed with heavily oiled snow and removed by a loader or bobcat. • Approximately 1,130 cubic yards of oiled snow is removed and transferred to a temporary lined storage pit constructed on the pad. The storage pit is 90 feet by 90 feet by 3 feet, with an additional 2 feet of freeboard. The pit is located south of Central Storage. Snow is piled in the pit to form a peak. **Winter:** • When the pond ice is thick enough for safe operations, a bobcat with trimmer attachment mechanically removes diesel-contaminated snow on the ponds to a depth of 6 inches. • Diesel contained by broken ice on the northeast shore of the ponds remains embedded in the ice as the ponds completely freeze. The trimmer then removes the diesel-contaminated ice. Oiled ice is transported to temporary lined storage pits constructed on the pad.	L-2 C-1 R-3, R-6(2) R-26 R-3 L-7, R-3 R-5
(viii) Lightering Procedures	Not applicable	Not applicable

TABLE 1-31 (CONTINUED)
DIESEL TANK RUPTURE DURING FREEZE-UP
RESPONSE STRATEGY

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECH. MANUAL TACTIC
(ix) Transfer and Storage of Recovered Oil/Water; Volume-Estimating Procedure	• Recovered diesel and water are hauled by vacuum truck across the pad to the facility's liquid process tanks for processing. Processed liquids are manifested. Oily sorbents are hauled by ATV on plywood paths to the pad. • Oiled snow and ice are transferred by loaders and stockpiled in interim storage on the pad until break-up. When the snow begins to melt, vacuum trucks recover and transport oily liquids to the processing facility.	D-1 D-2, D-1
(x) Plans, Procedures, and Locations for Temporary Storage and Disposal	Temporary storage facilities are established on the pad for contaminated snow, ice, and oily wastes. • Oily liquids are recycled and manifested. • Contaminated snow is hauled to the storage cell for melting and processing. The oiled snow is allowed to melt in the spring. Liquids are pumped off with vacuum trucks as they become available and transported to the processing facility. • 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 under a treatment plan approved by ADEC.	D-1 D-5 D-2 D-3 D-4
(xi) Wildlife Protection Plan	• The wildlife protection strategy is implemented. Monitors for Polar bears are assigned. • A bird-hazing team deploys passive hazing devices at the pond beginning on the first shift. • The Wildlife Stabilization Center is made operational in Deadhorse. No oiled animals are encountered.	W-1 W-2B W-5
(xii) Shoreline and Tundra Cleanup	• The shoreline is cleaned to the satisfaction of ADEC in the shortest possible time with teams of shoreline cleanup crews and equipment. Oily waste is hauled to a controlled and lined collection area on the pad, south of Central Storage. • Heavier pockets of stranded diesel are collected manually. • The ponds are monitored during and after break-up.	SH-1 SH-5

TABLE 1-32
DIESEL TANK RUPTURE DURING FREEZE-UP
OIL RECOVERY CAPACITY

A	B	C	D	E	F	G
SPILL RECOVERY TACTIC	**NUMBER OF SYSTEMS**	**RECOVERY SYSTEM**	**DERATED OIL RECOVERY RATE (boph)**	**MOBILIZATION, TRANSIT, AND DEPLOYMENT TIME TO SITE (hours)**	**OPERATING TIME (hours in a 24-hour shift)**	**DAILY DERATED OIL RECOVERY CAPACITY (bpd) (B x D x F)**
R-6	2	Vacuum Truck with Manta Ray Skimmer	27	1.5[1]	16[2]	864
R-3, R-26	1	Front End Loader	20	1.5[1]	20	400

[1] Time values taken from the ACS *Technical Manual*.
[2] Trucks operate 20 hours per day, but only 16 hours per day are spent in recovery operations and 4 hours per day are needed for offloading.

TABLE 1-33
DIESEL TANK RUPTURE DURING FREEZE-UP
LIQUID HANDLING CAPABILITY

A	B	H	I	J	K	L	M	N	O	P
SPILL RECOVERY TACTIC	**NUMBER OF STORAGE SYSTEMS**	**STORAGE CAPACITY DESCRIPTION**	**STORAGE CAPACITY (bbl)**	**OIL/EMULSION AVAILABLE (bph)**	**TIME ON LOCATION BEFORE OFFLOAD NEEDED (hours) (I/J)**	**OFFLOADING MECHANISM**	**OFF-LOADING RATE (bph)**	**TRANSIT TIME – BOTH WAYS (hours)**	**OFF-LOADING TIME (hours) (I/M)**	**OFFLOAD AND TRANSIT TIME (hours) (N+O)**
R-6	2	Vacuum Truck	100 each	27[1]	3.7[2]	Vacuum truck	200	0.5	0.5	1

[1] The total volume of diesel and free water available for storage is the recovered volume of diesel using a Manta Ray. Emulsification is not a factor.
[2] Time before offload is needed assumes a maximum derated recovery rate of 27 bph for a Manta Ray skimmer.

TABLE 1-34
DIESEL TANK RUPTURE DURING FREEZE-UP
MAJOR EQUIPMENT FOR RECOVERY AND TRANSFER

TACTIC	NO. TACTICAL UNITS	EQUIPMENT PER TACTICAL UNIT	TOTAL QUANTITY
C-1	1	Front-end Loader	1
R-3	1	Front-end Loader (shared with C-1)	1
		Bobcat	1
R-6	2	Vacuum Truck	2
		Manta Ray Skimmer Head	2
R-26	1	Front-end Loader	1
		Grader	1
R-5	1	Bobcat	1
		Trimmer	1
		Front-end Loader (shared with R-26)	1

TABLE 1-35
DIESEL TANK RUPTURE DURING FREEZE-UP
STAFFING TO OPERATE OIL RECOVERY AND TRANSFER EQUIPMENT

LABOR CATEGORY	TACTIC	NO. TACTICAL UNITS	NO. STAFF PER UNIT	NO. STAFF PER SHIFT[1]
Team Lead	R-3	1	1	1
	R-6	2	1	2
	R-5	1	1	1
Skilled Technician	R-3	1	1	1
	R-6	2	1	2
	R-5	1	2	2
	T-1	1	2	2
Equipment Operator	C-1	1	1	1
	R-3	1	2	2
	R-6	2	1	2
	R-26	1	2	2
	R-5	1	2	2
Total Technicians[2]	-	-	-	7

[1]The staffing schedule is shown in the column for number of staff per period. Number of staff recovering oil becomes zero after Hour 72.
[2]The total tallies the Technicians; Team Leads are Skilled Technicians.

FIGURE 1-12 DIESEL TANK RUPTURE DURING FREEZE-UP VICINITY MAP

FIGURE 1-13 DIESEL TANK RUPTURE DURING FREEZE-UP

SCENARIO 5

POINT THOMSON WELL BLOWOUT DURING WINTER

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TABLE 1-36
POINT THOMSON BLOWOUT DURING WINTER
SCENARIO CONDITIONS

INITIAL CONDITIONS	
Spill Location	Point Thomson CWP
Spill Time	March 1-15
Source of Spill	Uncontrolled well blowout through the casing and drill pipe annulus, open to the atmosphere
Type of Spill	Well blowout
Quantity of Spilled Oil	**RPS Volumes:** Day 1, Hours 0 to 2 (prior to well ignition): 517 bbl Sum of Day 1, Hours 2-24 Volume and Days 2 through 15 Volume (after well ignition): 206 bbl Total 15-day RPS Volume: 723 bbl
Oil Type	Condensate
Wind Speed	56 knots. This is the highest wind speed recorded for any 2-hour time period of wind data from the meteorological station located west of Point Thomson.
Wind Direction	From east (85 degrees) during first 2 hours on Day 1 and variable during remainder of Day 1. Variable winds from the east on Days 2 through 15.
Current	Lagoon frozen, no open water
Air Temperature	-15 ºF
Visibility	Unrestricted
Surface	The winter period is characterized by stable landfast (also called shorefast) ice. The sheet ice grows to an average maximum thickness of 6 to 7 feet by the end of May. This means that ice in the shallow waters throughout most of the lagoon between Point Thomson and Brownlow Point becomes frozen to the seafloor at the end of the ice growth cycle (Vaudrey, 1985c). Once the nearshore ice is established and stable, the seaward fast ice edge remains close to the 60-foot water depth in most years. The average water depths at the fast ice edge are approximately 45 to 50 feet from December to March. Off Flaxman Island, these water depths correspond to distances of 7 to 8 miles from shore in January to March (Dickins, 1985 unpublished).
Trajectory	The condensate is modeled to be ejected into the air, with a gas-to-condensate ratio of approximately 17,250 scf/bbl and gas flow rate of 465 mmscf/d. The well is located on the CWP. **Prior to Blowout Ignition:** The wind blows the condensate to the west of the well in the 2 hours prior to ignition, based on the most frequently measured wind direction, and the highest 2-hour velocity data from a meteorological station located west of Point Thomson. The deposition footprint is predicted by the SCIPUFF dispersion model using dodecane as a surrogate for condensate to simulate the well blowout scenario for the first 2 hours. On Day 1, during the first 2 hours of the blowout, condensate from the well impacts surfaces on the production pad and the surrounding area at the rate of 259 bph. 517 bbl of condensate is distributed over a lenticular area of 6.5 square miles or 4,127 acres [approximately 9.3 miles long x 0.9 mile wide at the broadest point] west of the well. Of this dispersion, 94.2 percent (487 bbl) falls within 9.3 miles of the well, at which distance the condensate thickness is less than 0.001 millimeter (mm) (0.00004 inch). Approximately 5.8 percent (30 bbl) of condensate that moves westward as fine airborne particulates does not precipitate or settle onto the ground surface. Figure 1-14 illustrates the condensate dispersion at Hour 2 of the well blowout. Condensate falling to the pad accumulates in depressions. Condensate falling onto the frozen, snow-covered surfaces accumulates at a thickness ranging from 10 mm (0.4 inch) next to the well to 0.001 mm (0.00004 inch) at a distance of 9.3 miles. Approximately 55 percent (284 bbl) of the condensate falls in a 0.17 square mile (109 acres) lens extending approximately 1 mile west of the well. The original condensate thickness in this area averages 1 mm (0.04 inch). Under the 56-knot wind, the condensate mixed with snow blows into windrows having an average condensate thickness of 2 mm (0.08 inch) on half of the area (54.5 acres).

TABLE 1-36 (CONTINUED)
POINT THOMSON BLOWOUT DURING WINTER
SCENARIO CONDITIONS

INITIAL CONDITIONS	
Trajectory (continued)	From 1 mile to 3 miles west of the well, an additional 26 percent (134 bbl) of the condensate falls in a 1-square mile (640 acres) lens. The average condensate thickness in this lens is 0.05 mm (0.002 inch). Under the 56 knot wind, the condensate mixed with snow blows into windrows having an average condensate thickness of 0.1 mm (0.004 inch) on half of the area (320 acres). The remaining condensate that precipitates or settles onto the ground surface is 12.9 percent (67 bbl) of the total released from the blowout in the first 2 hours. This condensate falls in a 5.25 square mile (3,360 acres) lens. The average condensate thickness upon deposition is 0.005 mm (0.002 inch). Under the 56-knot wind, the condensate mixed with snow blows into windrows having an average condensate thickness of 0.01 mm (0.0004 inch) on half of the area (1,680 acres). **After Blowout Ignition:** 90 percent of the condensate is lost to combustion when the aerial plume ignites on Day 1, Hour 2. The scenario assumes that 1 percent of the unburned condensate is liquid, with the remaining 99 percent as soot. The 1 percent of the unburned condensate which falls to the ground surface (206 bbl) is distributed variably in every direction around the well. The 206 bbl is dispersed so thinly that it is infeasible to detect and pick up by cleanup task forces. A diagram is not provided for the blowout scenario for the period after the well is ignited. It is assumed a volume of 517 bbl of condensate falls out to the west during the 2 hours prior to ignition and 206 bbl of condensate are distributed in the area surrounding the well during the 14 days and 22 hours after the well is ignited, for a total of 723 bbl from the well blowout.

TABLE 1-37
POINT THOMSON BLOWOUT DURING WINTER
RESPONSE STRATEGY

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(i) Stopping Discharge at Source	The Drilling Supervisor notifies the Drilling Operations Superintendent. The Drilling Supervisor takes the role of the Initial On-Scene Commander, until relieved by the Drilling Operations Superintendent. The Drilling Supervisor makes the decision to ignite the well at Hour 2. Well control experts are called out from Houston, Texas, arriving in 24 hours. The appropriate agency notifications are made. The Incident Management Team is activated. The scenario assumes that the blowout is voluntarily ignited at the rig floor on Day 1, Hour 2. The effect of the ignition on operations is to (1) increase safety by removing toxic and flammable gases, and (2) decrease pollution of the frozen land and water surface.	A-1 A-2 Vol. 3 IMS L-5 L-9 See Plan Section 1.6.3
(ii) Preventing or Controlling Fire Hazards	The Site Safety Officer, Incident Commander, and Company Representative set up access zones and routes and fire-fighting operations to protect assets and workers. The Site Safety Officer determines personal protective equipment (PPE) requirements and provides hot and warm zone access information. Access to the spill site is carefully controlled and the scene is secured by Security. Monitoring protocol is established by the Site Safety Officer 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 allowed without respiratory protection in areas where safety criteria are met. Recovery operations and oil field operations and traffic are disallowed downwind of the blowout well in areas where cleanup workers may become exposed to flash fire hazard or oil particulate matter at concentrations in excess of permissible exposure limits.	S-1 through S-6
(iii) Well Control Plan	Over the course of 15 days, a new capping stack is installed. The oil from the well burns without interruption until it is diverted with the capping stack as part of the kill step. See Section 1.6.3 for a description of well control.	Plan Section 1.6.3
(iv) Surveillance and Tracking of Oil; Forecasting Shoreline Contact Points	The extent of oil on the snow is delineated beginning on Day 1 so that it can be found if subsequent snowfall or blowing snow covers the spill. Delineation team will use Tucker snowcat and snow machines for ground transportation.	T-1 T-2
(v) Exclusion Procedures; Protection of Sensitive Resources	The ACS *Technical Manual Map Atlas*, Sheet 103, is consulted to determine shoreline sensitivities and priority protection sites. No priority protection sites lie in the spill trajectory. The area is monitored for birds and mammals that may be at risk from the spill.	Map Sheet #103 L-2
(vi) Spill Containment and Control Actions	**Day 1:** When it is determined safe to do so, snow berms are constructed upwind of the blowout to provide initial containment. Containment berms are constructed to the north, east, and south of the pad in an effort to contain condensate on the pad. Vacuum trucks pump condensate accumulating within the bermed areas. A temporary containment area is constructed. One 50-foot x 200-foot x 2-foot lined storage pit is excavated in the CPF pad east of the Construction Camp parking area. The pits are bermed with the excavated gravel to a height of 3 feet. The pits contain snow piled to a height of 15 feet. This storage area is used for staging contaminated snow. A staging area is constructed in the Construction Camp and the Construction Camp parking area.	C-1 R-6

TABLE 1-37 (CONTINUED)
POINT THOMSON BLOWOUT DURING WINTER
RESPONSE STRATEGY

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(vi) **Spill Containment and Control Actions (Continued)**	**Days 2 Through 15:** After well ignition at Hour 2, the wind shifts from a predominantly easterly wind to a variable wind. The total volume of condensate falling to the frozen ground and ice surface is reduced to less than 14 bbl per day. This condensate falls to the ground and is absorbed by snow and ice. No additional containment is required.	L-2
(vii) Spill Recovery Procedures	**Day 1:** Task Force 1: On the pad, a loader mixes snow with remaining free condensate where it is safe and places the mixture into a lined containment area. Vacuum trucks remove any remaining pools of condensate from the pad. **Days 2 Through 15:** Beginning on Day 2, an ice road is constructed extending 1 mile west of the well. The ice road is constructed to provide equipment access to the area most heavily oiled. The road is constructed using a grader from Point Thomson. The water truck is mobilized from Prudhoe Bay by Rolligon. Assuming a 1-day mobilization to Point Thomson, a 1-mile ice road would be completed by the end of Day 3. Task Forces focus on recovering condensate that previously fell to the west of the well during the first 2 hours of Day 1. Recovery of contaminated snow covering river and lake environments is addressed first. • Task Force 1 (TF-1) recovers oiled snow from safe areas extending out approximately 1 mile. TF-2 mobilizes on Day 3 after completion of the ice road. Two dump trucks are mobilized to Point Thomson from Prudhoe Bay by Rolligon. The trucks are deployed on Day 1, Hour 2, and arrive at Point Thomson on Day 3. The objective is to recover the 284 bbl of condensate deposited on approximately 109 acres. • Task Force 2 (TF-2) manually recovers lightly misted snow extending from approximately 1 mile west of the well to 3 miles west of the well. TF-2 consists of two recovery teams that transport recovered snow by snow machine to the constructed ice road where the snow is loaded into dump trucks. The objective of TF-2 is to manually recover, as practicable, the 134 bbl of lightly misted condensate from approximately 640 acres. An additional 67 bbl of condensate was deposited in a lens extending from 3 miles to 9.3 miles west of the well. The Unified Command determines it is not practical to recover condensate beyond 3 miles without damage to the ground surface.	R-3 L-1 R-6 (2) R-2, R-1 R-1A (2)
(viii) Lightering Procedures	Not applicable	Not applicable
(ix) Transfer and Storage of Recovered Oil/Water; Volume-Estimating Procedure	Recovered oil is hauled by vacuum truck across the pad to the facility's liquid process tanks for processing. Processed liquids are manifested. Oiled snow and ice are transferred by loaders and dump trucks to the lined storage area until break-up. When the snow begins to melt, the oily liquids will be transferred to the processing facility. A Waste Team member at each receiving facility logs the quantity of oil estimated with a Coliwasa tube in the vacuum truck tanks and the quantity of oiled snow and ice dumped into lined pits. The oil volume and water cut in vacuum trucks hauling oil separated from melting snow can be estimated with a Coliwasa tube.	D-1 R-6 D-2 D-5

TABLE 1-37 (CONTINUED)
POINT THOMSON BLOWOUT DURING WINTER
RESPONSE STRATEGY

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(x) Plans, Procedures, and Locations for Temporary Storage and Disposal	Temporary storage facilities are established on the pad, for contaminated snow, ice, and oily wastes. • Oily liquids are injected into the disposal well. • Contaminated snow is hauled to the storage cell for melting and processing. The oiled snow is allowed to melt in the spring. Liquids are pumped off and transported to the processing facility. • 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 treated under a contaminated soil and stockpiled under a treatment plan approved by ADEC.	D-1 D-5 D-2 D-3 D-4
(xi) Wildlife Protection Plan	The wildlife protection strategy is implemented. Polar bear monitors are assigned. A bird hazing team deploys passive hazing devices beginning on the first shift. The Wildlife Stabilization Center is made operational in Deadhorse. No oiled animals are encountered.	W-1 W-2B W-5
(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, the Shoreline Cleanup Assessment Team (SCAT) monitors the tundra and adjacent shorelines for oiling according to the plan and find none. Ponds are monitored during and after break-up as a non-emergency project.	SH-1 SH-5 See p. 3-28

TABLE 1-38
POINT THOMSON BLOWOUT DURING WINTER
OIL RECOVERY CAPACITY

A	B	C	D	E	F	G
SPILL RECOVERY TACTIC	**NUMBER OF SYSTEMS**	**RECOVERY SYSTEM**	**DERATED OIL RECOVERY RATE (boph)**	**MOBILIZATION, TRANSIT, AND DEPLOYMENT TIME TO SITE (hours)[1,2]**	**OPERATING TIME (hours in a 24-hour shift)**	**DAILY DERATED OIL RECOVERY CAPACITY (bpd) B X D X F**
TF-1: R-2	1	Manual Recovery	0.9	48	20	18
TF-1: R-1	1	Loader, 2 Dump Trucks	39	48	20	780
TF-2: R-2	2	Manual Recovery	0.9	48	20	36

1 TF-1 and TF-2 recovery begins when safe working zone is established on Day 2, and rolling stock arrives from Prudhoe Bay.

2 Recovery rates are calculated with ACS *Technical Manual* planning capacities, as follows:

- TF-1 R-1 is limited by the dump trucks. Using two 20-yard dumps and a maximum one-way travel distance of 1 mile and the planning capacity of 0.3 bbl of oil per cubic yard of snow, the daily recovery rate is 780 bbl. Tactic R-2 uses one team of six laborers generating 10 cubic yards per shift, 2 shifts per day. Assuming 0.9 bbl of oil per cubic yard, the recovery rate is 18 bbl per day.
- TF-2 uses Tactic R-2 with two crews. Assuming 18 bopd per crew, TF-2 recovers 36 bopd.

TABLE 1-39
POINT THOMSON BLOWOUT DURING WINTER
MAJOR EQUIPMENT EQUIVALENTS TO MEET THE RESPONSE PLANNING STANDARD

RECOVERY TACTIC	NO. TACTICAL UNITS	EQUIPMENT PER TACTICAL UNIT	TOTAL QUANTITY
R-1	1	1 each Front Loader	1
		2 each 20-yard Dump	2
R-1A	2	3 each Snow Machine (shared with R-2)	6
		1 each Snow Blower	2
R-2	1	3 each Snow Machine (shared with R-1A)	3
		1 each Front Loader	1
R-3	1	1 each Front loader	1

TABLE 1-40
POINT THOMSON BLOWOUT DURING WINTER
NUMBER OF STAFF PER SHIFT TO OPERATE OIL RECOVERY AND TRANSFER EQUIPMENT

LABOR CATEGORY	TASK FORCE AND TACTIC	NO. TACTICAL UNITS	NO. STAFF PER TACTICAL UNIT	NUMBER OF STAFF PER SHIFT		
				DAY 1	DAYS 2 AND 3	DAYS 3 THROUGH 15
Team Lead	TF1: R-3	2	1	1		
	TF1: R-1, R-2	2	1		1	1
	TF2: R-1A	2	1			1
Skilled Technician	TF1: R-3	2	1	1		
	TF1: R-1, R-2	2	1		5	5
	TF2: R-1A	2	1			2
General Technician	TF1: R-3	2	2	4		
	TF1: R-1, R-2	2	1		20	20
	TF2: R-1A	2	1			6
Total Technicians				5	25	33

Note: Totals exclude team leads because they are tallied as skilled technicians. The staffing schedule is shown in the column for number of staff per shift. Number of staff per shift decreases to zero after the day represented in the last column.

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FIGURE 1-14 BLOWOUT DURING WINTER: EXTENT OF BLOWOUT PLUME PRIOR TO IGNITION

FIGURE 1-15 BLOWOUT DURING WINTER: RECOVERY TACTICS

SCENARIO 6

POINT THOMSON WELL BLOWOUT DURING SUMMER

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TABLE 1-41
POINT THOMSON CONDENSATE BLOWOUT DURING SUMMER
SCENARIO CONDITIONS

INITIAL CONDITIONS	
Spill Location	Point Thomson CWP
Spill Time	August 1-15
Source of Spill	Uncontrolled well blowout through the casing and drill pipe annulus, open to the atmosphere
Type of Spill	Well Blowout
Quantity of Spilled Oil	RPS Volumes: Day 1, Hours 0 to 2 (prior to well ignition): 517 bbl Sum of Day 1, Hours 2-24 Volume and Days 2 through 15 Volume (after well ignition): 206 bbl Total 15-day RPS Volume: 723 bbl
Oil Type	Condensate
Wind Speed	18 knots
Wind Direction	From southwest during first 2 hours on Day 1 and variable during remainder of Day 1. Variable on Days 2 through 15.
Current	Marine surface water flows 0.6 knots at 3 percent of wind speed.
Air Temperature	40ºF
Visibility	Unrestricted
Trajectory	The condensate is modeled to be ejected into the air, with a gas-to-condensate ratio of approximately 17,250 scf/bbl and gas flow rate of 465 mmscf/d. The well is located on the CWP. **Prior to Blowout Ignition:** The wind blows the condensate to the northeast of the well in the 2 hours prior to ignition, based on the most frequently measured wind direction and velocity data from a meteorological station located west of Point Thomson. The deposition footprint is predicted by the SCIPUFF dispersion model using dodecane as a surrogate for condensate to simulate the well blowout scenario for the first 2 hours. On Day 1, during the first 2 hours of the blowout, condensate from the well impacts surfaces on the production pad and the surrounding area at the rate of 259 bph. A total of 517 bbl of condensate is distributed over a lenticular area of 3.6 square miles or 2,304 [approximately 5.3 miles long x 0.68 mile wide at the broadest point] northeast of the well. Of this dispersion, 85.5 percent (442 bbl) falls within 5.3 miles of the well. On the sea at that distance, the condensate under the plume is less than 0.001 mm thick (0.00004 inch) and spreads thinner as it is carried by currents. Approximately 14.5 percent (75 bbl) of condensate that moves over the sea as fine airborne particulates disperses and does not settle or enter water. Condensate thickness and deposition were predicted using the SCIPUFF model. Volumes of condensate fallout to the tundra and pad gravel were extrapolated from the model results. Figure 1-16 shows the deposition of the condensate on land and water at Hour 2. **Condensate Deposition to Land:** Volume retained in pad gravel = 44 bbl Volume retained in tundra on shore = 47 bbl Volume retained in tundra on Mary Sachs Island = 5 bbl **Condensate Deposition to Open Water:** **Area A** is 1 to 10 mm thick, and covers approximately 0.0468 square kilometer (0.02 square mile). Approximately 50 percent of the condensate in Area A falls to open water; thus the volume of condensate offshore in Area A is 84 bbl. **Area B** is 0.1 to 1 mm thick and covers approximately 0.388 square kilometer (0.15 square mile). Approximately 97 percent of the condensate in Area B falls to open water; thus the volume of condensate offshore in Area B is 165 bbl.

TABLE 1-41 (CONTINUED)
POINT THOMSON CONDENSATE BLOWOUT DURING SUMMER
SCENARIO CONDITIONS

INITIAL CONDITIONS	
Trajectory (continued)	**Area C** is 0.01 to 0.1 mm thick and covers approximately 1.93 square kilometers (0.75 square mile). Approximately 92 percent of the condensate in Area C falls to open water; thus the volume of condensate offshore in Area C is 73 bbl. **Area D** is 0.001 to 0.01 mm thick and covers approximately 6.91 square kilometers (2.67 square miles). Approximately 96 percent of the condensate in Area D falls to open water; thus the volume of condensate offshore in Area D is 25 bbl. The condensate in Area D is not visible to the eye at deck level, nor is it recoverable by mechanical equipment due to its low viscosity. The Unified Command makes the decision to forego targeting condensate in this area based on these reasons **After Blowout Ignition:** 90 percent of the condensate is lost to combustion when the aerial plume ignites on Day 1, Hour 2. The scenario assumes that 1 percent of the unburned condensate is liquid, with the remaining 99 percent as soot. The 1 percent, or 206 bbl, of the unburned condensate falls to the surface and is variably distributed in fine droplets in every direction around the well. The 206 bbl is so thinly distributed that it is infeasible to detect and pick up by cleanup task forces. A diagram is not provided for the blowout scenario for the period after the well is ignited. It is assumed a volume of 517 bbl of condensate falls out to the northeast during the 2 hours prior to ignition and 206 bbl of condensate are distributed in the area surrounding the well during the 14 days and 22 hours after the well is ignited, for a total of 723 bbl released during the well blowout. Over the course of the blowout, condensate spilled to open water is influenced by ocean currents and variable winds. These ocean currents and winds move the condensate toward the northern and southern shorelines of Mary Sachs Island, where unrecoverable condensate becomes stranded by the end of the blowout.

TABLE 1-42
POINT THOMSON CONDENSATE BLOWOUT DURING SUMMER RESPONSE STRATEGY

ADEC REQUIREMENT		RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(i)	**Stopping Discharge at Source**	The Drilling Supervisor notifies the Drilling Operations Superintendent. The Drilling Supervisor takes the role of the Initial On-scene Commander, until relieved by the Drilling Operations Superintendent. The Drilling Supervisor makes the decision to ignite the well at Hour 2. Well control experts are called out from Houston, Texas, arriving in 24 hours. The appropriate agency notifications are made. The IMT is activated. The scenario assumes that the blowout is voluntarily ignited at the rig floor on Day 1, Hour 2. The effect of the ignition on operations is to (1) increase safety by removing toxic and flammable gases, and (2) decrease pollution of the land and water surface.	A-1 A-2 Vol. 3 IMS L-5 L-9 Plan Section 1.6.3
(ii)	**Preventing or Controlling Fire Hazards**	The Site Safety Officer, Incident Commander, and Company Representative set up access zones and routes and fire-fighting operations to protect assets and workers. The Site Safety Officer determines PPE requirements and provides hot and warm zone access information. Access to the spill site is carefully controlled and the scene is secured by Security. Monitoring protocol is established by the Site Safety Officer 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 allowed without respiratory protection in areas where safety criteria are met. Recovery operations and oil field operations and traffic are not allowed downwind of the blowout well in areas where cleanup workers may become exposed to flash fire hazard or oil particulate matter at concentrations in excess of permissible exposure limits.	S-1 through S-6
(iii)	**Well Control Plan**	Over the course of 15 days, a new capping stack is installed. The oil from the well burns without interruption until it is diverted with the capping stack as part of the kill step. See Section 1.6.3 for a description of well control.	Plan Section 1.6.3
(iv)	**Surveillance and Tracking of Oil; Forecasting Shoreline Contact Points**	Aerial observation from aircraft provides real-time tracking of the oil. A survey crew delineates the spill-affected area at on the gravel and tundra. NOAA is requested to provide trajectories based on wind speed and direction.	T-4 T-2 T-5
(v)	**Exclusion Procedures; Protection of Sensitive Resources**	The ACS *Technical Manual Map Atlas*, Sheets 99, 100, and 103 are consulted to determine shoreline sensitivities and priority protection sites. No priority protection sites lie in the spill trajectory. The area is monitored for birds and mammals that may be at risk from the spill.	See Maps 99, 100, and 103 W-6

TABLE 1-42 (CONTINUED)
POINT THOMSON CONDENSATE BLOWOUT DURING SUMMER
RESPONSE STRATEGY

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(vi) Spill Containment and Control Actions **and** **(vii) Spill Recovery Procedures**	A staging and decontamination area and field command post are set up at the CPF in the parking area located east of Building 201. **CPF and Tundra Task Force:** Day 1, Hour 8 to Day 3 • After the decontamination area is set up, Team 1 places shoreseal boom and sorbent boom on the perimeter of the contaminated tundra to deflect and contain condensate. Team 1 also constructs gravel berms on the pad to ensure that the condensate remains trapped in the immediate areas and depressions. • Team 2 cleans the tundra and gravel. Crews flush low-pressure water over the tundra, moving condensate down to collection areas where it is recovered with vacuum truck hoses and sorbent material. A vacuum truck collects from a position near the edge of the pad, with a Manta Ray skimmer head attached to the intake hose. The truck carries the oil to the disposal well for recycling, if safe to do so; otherwise, the truck will move to the staging area until safe to dispose in the disposal well. **Near Shore Recovery Task Force:** Day 1, Hour 4 to Day 3 Team 3 deploys offshore in the Beaufort Sea, 4 hours following well ignition. The team objective is to recover oil on water. The team works to recover condensate closest to the shorelines in Areas A and the parts of Areas B and C closest to the shore. Team 3 uses an airboat with closed tank and drum/brush combination skimmer and a boom-towing skiff to form a "J" boom configuration for recovery. The airboat unloads recovered fluids to a mini-barge towed by an Island Class vessel that then unloads to a vacuum truck at the Point Thomson dock. The team works close to the impacted shorelines of Mary Sachs Island. **Open Water Recovery Task Force:** Day 1, Hour 4 to Day 3 Team 4 has the objective of recovering oil moving in windrows toward and past Mary Sachs Island on Day 1 and beyond. Team 4 uses the skimming vessel equipped with a MARCO Filter Belt skimmer and built in storage, along with a 20-foot airboat to form a "J" boom configuration for recovery. The skimming vessel unloads recovered fluids to a mini-barge towed by an Island Class vessel.	L-2 C-4 R-4, R-6 R-17 R-17(2)
(viii) Lightering Procedures	No on-water lightering	
(ix) Transfer and Storage of Recovered Oil/Water; Volume-Estimating Procedure	Condensate recovered by the nearshore and open water task forces is pumped into mini-barges shuttled by an Island Class vessel. The Island Class vessel tows a loaded mini-barge from recovery vessels to Point Thomson dock for off-loading to a vacuum truck. The number and turnaround time of mini-barge transfers of stored liquid occurs at a greater rate than it is collected and, consequently, transfer does not constrain the on-water recovery rates. Ullage tape and Coliwasa tubes gauge liquid volumes and water in the vacuum trucks for waste manifests.	R-22

TABLE 1-42 (CONTINUED)
POINT THOMSON CONDENSATE BLOWOUT DURING SUMMER
RESPONSE STRATEGY

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(x) Plans, Procedures, and Locations for Temporary Storage and Disposal	Temporary storage facilities in bermed, lined pits are established at CPF pad for oily wastes under a plan approved by the Unified Command and ADEC. Liquid and non-liquid wastes are characterized and disposed of accordingly. Recovery liquids are disposed of in the Class 1 disposal well. After liquids are removed, grid sampling indicates the depth of gravel penetration, and the contaminated gravel is excavated. The contaminated gravel is transported to a lined containment area south of Central Storage and stored for later handling.	D-1, D-2, D-3, D-4 R-26
(xi) Wildlife Protection Plan	Resources at risk are primarily birds. • The wildlife protection strategy is implemented on Day 1. • Wildlife hazing teams are deployed on oiled marine shorelines. • The Wildlife Stabilization Center is made operational at Deadhorse. • As oiled wildlife are identified, capture teams are deployed to the spill scene. • Captured birds are carried by wildlife response skiff to Point Thomson, where they are flown in fixed-wing aircraft to Deadhorse for treatment.	W-1 W-2B W-5 W-3
(xii) Shoreline Cleanup Plan	**Shoreline Cleanup Task Force:** Days 3-5 • Oil on the limited vegetation on Mary Sachs Island cannot be recovered without further damage to the environment. The Unified Command approves a plan for burning oiled vegetation on Mary Sachs Island. • Team 5 is deployed to Mary Sachs Island to begin burning the limited oily vegetation, where possible. Burning is conducted so that smoke and burning embers do not interfere with activities occurring downwind. • The shoreline is cleaned up to the satisfaction of ADEC in the shortest possible time with teams of shoreline cleanup crews and equipment. Oily waste is hauled to a controlled and lined collection area on the pad, south of Central Storage. • Heavier pockets of stranded condensate are collected manually. • Minor to moderately oiled areas near the pad are deluged to recover condensate. • On the tundra near the pad and on Mary Sachs Island, contaminated vegetation is left in place. Some is burned to reduce re-oiling of adjacent habitat.	SH-1 SH-5 SH-3 B-1, B-2 B-1, B-2

TABLE 1-43
POINT THOMSON CONDENSATE BLOWOUT DURING SUMMER
OIL RECOVERY CAPACITY

A	B	C	D	E	F	G
SPILL RECOVERY TACTIC	**NUMBER OF SYSTEMS**	**RECOVERY SYSTEM**	**DERATED RECOVERY RATE (bph)**	**MOBILIZATION, TRANSIT, AND DEPLOYMENT TIME TO SITE (hours)**	**OPERATING TIME (hours in a 24-hour shift)**	**MAXIMUM DAILY DERATED OIL RECOVERY CAPACITY (bpd) (B x D x F)**
R-6	1	Vacuum Truck with Manta Ray skimmer	27	1.5	16[1]	432
R-17 (nearshore)	1	Drum/Brush Combination Skimmer	28	4	20	560
R-17 (open water)	1	MARCO Filter Belt Skimmer	10	4	20	200

1. Truck operates 20 hours per day, but 16 hours per day are spent recovering and 4 hours per day are needed for offloading.

TABLE 1-44
POINT THOMSON CONDENSATE BLOWOUT DURING SUMMER
LIQUID HANDLING CAPABILITY

A	B	H	I	J	K	L	M	N	O	P
SPILL RECOVERY TACTIC	**NUMBER OF STORAGE SYSTEMS**	**STORAGE CAPACITY DESCRIPTION**	**STORAGE CAPACITY (bbl)**	**OIL/EMULSION AVAILABLE (bph)**	**TIME ON LOCATION BEFORE OFFLOAD NEEDED (hours) (I/J)**	**OFFLOADING MECHANISM**	**OFF-LOADING RATE (bph)**	**ROUND TRIP TRANSIT TIME (hours)**	**OFF-LOADING TIME (hours)**	**OFFLOAD AND TRANSIT TIME (hours) (N+O)**
R-17	2	Mini-barge	237 each	2[1]	30	3-inch Trash pump[3]	158	1.5 (average)	1.5	3
R-22	2	Fold-a-Tank	36 each	2[1]	4.6	4-inch Trash pump[4]	1,074	N/A[5]	0.17	N/A[5]
R-6	1	Vacuum Truck	100	1.6[2]	62.5	Vacuum Truck	200	0.5	0.5	1

1. Total recoverable oil to water equals 347 bbl. Oil/emulsion available is based on 20 working hours per day minus 4 hours to deploy, which equals 56 working hours occurring within a 72-hour period: (347 bbl ÷ 56 hr = 6.2 bph). Condensate does not form an emulsion with water; therefore there is no emulsification factor.
2. Total recoverable oil to tundra/pad equals 91 bbl. Oil/emulsion available is based on 20 working hours per day minus 4 hours to deploy, which equals 56 working hours occurring within a 72-hour period: (91 bbl ÷ 56 hr = 1.6 bph). Condensate does not form an emulsion with water; therefore there is no emulsification factor.
3. Recovered liquids are offloaded from mini-barges into Fold-a-Tanks at the Point Thomson dock using a 3-inch Trash pump.
4. Recovered liquids are offloaded from Fold-a-Tanks into a Vacuum Truck using a 4-inch Trash pump.
5. Not applicable because Fold-a-Tanks are stationary.

TABLE 1-45
POINT THOMSON CONDENSATE BLOWOUT DURING SUMMER
MAJOR EQUIPMENT EQUIVALENTS TO MEET THE RESPONSE PLANNING STANDARD

RECOVERY TACTIC	NO. TACTICAL UNITS	EQUIPMENT PER TACTICAL UNIT	TOTAL QUANTITY
R-4	1	Fold-a-Tank	1
		2-inch Trash pump	1
		Suction and Discharge hose	Variable
R-6	1	Vacuum Truck (shared with R-22)	1
		DOP pump with power pack	1
		Manta Ray Skimmer	1
		Suction and Discharge hose	Variable
R-17 (nearshore team)	1	Airboat	1
		Boom towing skiff	1
		Boom	500 ft
		Closed tank	1
		Drum/brush combination skimmer	1
R-17 (open water team)	1	Skimming vessel (has built-in MARCO Filter Belt skimmer and storage)	1
		Airboat	1
		Boom	350 ft
		Island Class vessel (shuttles mini-barge; shared between R-17 teams)	1
		Mini-barge (shared between R-17 teams)	2
		3-inch Trash pumps (used with R-22)	1
R-22	1	Fold-a-Tank	2
		4-inch Trash pump	1
		Vacuum truck (shared with R-6)	1
		Suction and Discharge hose	Variable

TABLE 1-46
POINT THOMSON CONDENSATE BLOWOUT DURING SUMMER
NUMBER OF STAFF PER SHIFT TO OPERATE OIL RECOVERY AND TRANSFER EQUIPMENT

LABOR CATEGORY	TACTIC	NO. TACTICAL UNITS	NO. STAFF PER TACTICAL UNIT	NO. STAFF PER SHIFT
Team Lead	R-4	1	1	1
	R-6	1	1	1
	R-17 (nearshore)	1	1	1
	R-17 (offshore)	1	1	1
	R-17 (shuttle)	1	1	1
	R-22	1	1	1
Skilled Technician	R-4	1	1	1
	R-6	1	2	2
	R-17 (nearshore)	1	2	2
	R-17 (offshore)	1	2	2
	R-17 (shuttle)	1	1	1
	R-22	1	2	2
General Technician	R-4	1	1	1
	R-6	1	1	1
	R-17 (nearshore)	1	2	2
	R-17 (offshore)	1	2	2
	R-17 (shuttle)	1	1	1
	R-22	1	2	2
Vessel Operator	R-17 (nearshore)	1	2	2
	R-17 (offshore)	1	2	2
	R-17 (shuttle)	1	1	1
Equipment Operator	R-6 & R-22 (share a vacuum truck)	1	1	1
Total Staff				25

Note: Total excludes Team Leads because they work as Skilled Technicians or Vessel Operators.

FIGURE 1-16 BLOWOUT DURING SUMMER: EXTENT OF BLOWOUT PLUME

FIGURE 1-17 BLOWOUT DURING SUMMER: RECOVERY TACTICS

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1.7 NONMECHANICAL RESPONSE OPTIONS [18 AAC 75.425(e)(1)(G)]

ExxonMobil will mechanically contain and cleanup oil spills to the maximum extent possible. ExxonMobil will request approval for *in situ* burning of condensate or diesel on land or water surfaces from the FOSC and State On-Scene Coordinator (SOSC) when mechanical response methods prove ineffective or when *in situ* burning can be used as a tool to minimize environmental damage. The term *in situ* burning applies to burning oil that has reached surfaces and excludes ignition of blowout oil plumes and burning of collected waste oil.

1.7.1 Obtaining Permits and Approvals

In situ burning of spilled oil will not occur without approval of state and federal agencies. The ExxonMobil Incident Commander will discuss the option of *in situ* burning with the FOSC and the SOSC. ExxonMobil and ACS will follow ARRT "*In Situ* Burning Guidelines for Alaska" and complete the Guidelines' "Application for ISB."

ACS Tactics B-1 and B-1A

1.7.2 Decision Criteria for Use

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

ACS Tactic B-1

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

1.7.3 Implementation Procedures

If the Incident Commander decides to use *in situ* burning and obtains the necessary authorization, ACS would carry out the response. See Section 3.7 for a description of implementation and equipment.

ACS Tactics B-1 through B-7

1.7.4 Required Equipment and Personnel

ACS maintains the equipment and personnel for *in situ* burning.

ACS Tactic L-6

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

Diagrams of the Point Thomson facility are provided in this section and in the ACS *Technical Manual, Volume 2, Map Atlas*, Sheets 101 to 104.

ACS *Technical Manual, Volume 2, Map Atlas*

FIGURE 1-18 POINT THOMSON GAS CYCLING PROJECT VICINITY MAP

FIGURE 1-19 PIPELINE AND VALVE LOCATIONS

FIGURE 1-20   CENTRAL WELL PAD

FIGURE 1-21   CENTRAL PROCESSING FACILITY

FIGURE 1-22 EAST WELL PAD

FIGURE 1-23   WEST WELL PAD

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