Chapter Six: Oil and Gas in the North Slope Foothills Area

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Chapter Six: Oil and Gas in the North Slope Foothills Area

A. Geology

The North Slope Foothills lease sale area is distinct from and a subset of the North Slope Foothills Province (NSFP), which is a regional geologic feature that is part of Alaska's east-west trending North Slope Petroleum Province. The NSFP is nestled between the Brooks Range Province to the south and the Coastal Plain Province to the north. The NSFP encompasses more than 40,000 square miles, including the lease sale area lands, the southern part of the North Slope Areawide lands, greater than half the federally-managed NPR-A lands, the southern portion of ANWR 1002 area lands, various native corporation lands, and lands of mixed ownership on the far western North Slope. The NSFP regional depositional history is divided into four main sequences distinguished by sediment provenance, depositional style, and tectonics. These four sequences are listed (oldest to youngest) and discussed below.

The Franklinian sequence consists of fractured argillites, quartzites, carbonates, volcanics, and granitic rocks that once composed a stable continental platform prior to Devonian time 400 million years ago (Table 6.1). The Franklinian sequence includes the oldest sedimentary rocks in the NSFP and is considered effective basement for oil and gas potential (Figure 6.1). It is unlikely to contain any significant oil or gas accumulations in the foothills; however, if such accumulations are present they would likely be in the form of fractured reservoirs. During Late Devonian time, the Franklinian sequence was uplifted and deformed with coincident erosion of this uplifted sequence providing the dominant sediment source for the Ellesmerian sequence (Figure 6.2).

The Ellesmerian sequence consists of marine carbonates and clastic rocks rich in quartz and chert that were deposited on a subsiding foldbelt terrain for 150 million years during Mississippian to Early Jurassic time (Table 6.1). It is subdivided into a lower and upper section. The lower

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Mississippian Lisburne Group carbonates north of the village of Anaktuvuk Pass, south of the North Slope Foothills lease sale area.

Ellesmerian section contains proven oil and gas accumulations in the Coastal Plain Province, such as the Endicott, Lisburne, and Liberty oil fields. The upper Ellesmerian section contains proven oil and gas accumulations such as the Prudhoe Bay, Northstar, and Raven oil fields and the Kemik, Kavik, and Sandpiper gas fields. The Shublik Formation and Sadlerochit Group are two of the most continuous rock units in this section (Figure 6.1). The Ellesmerian sequence thins to the south due to increasing distance from its source area and thins to the north due to the combined effects of onlap, subaerial uplift, and erosion prior to deposition of the Beaufortian Rift sequence (Figure 6.2; Moore et al. 1994).

Table 6.1. Geologic time.

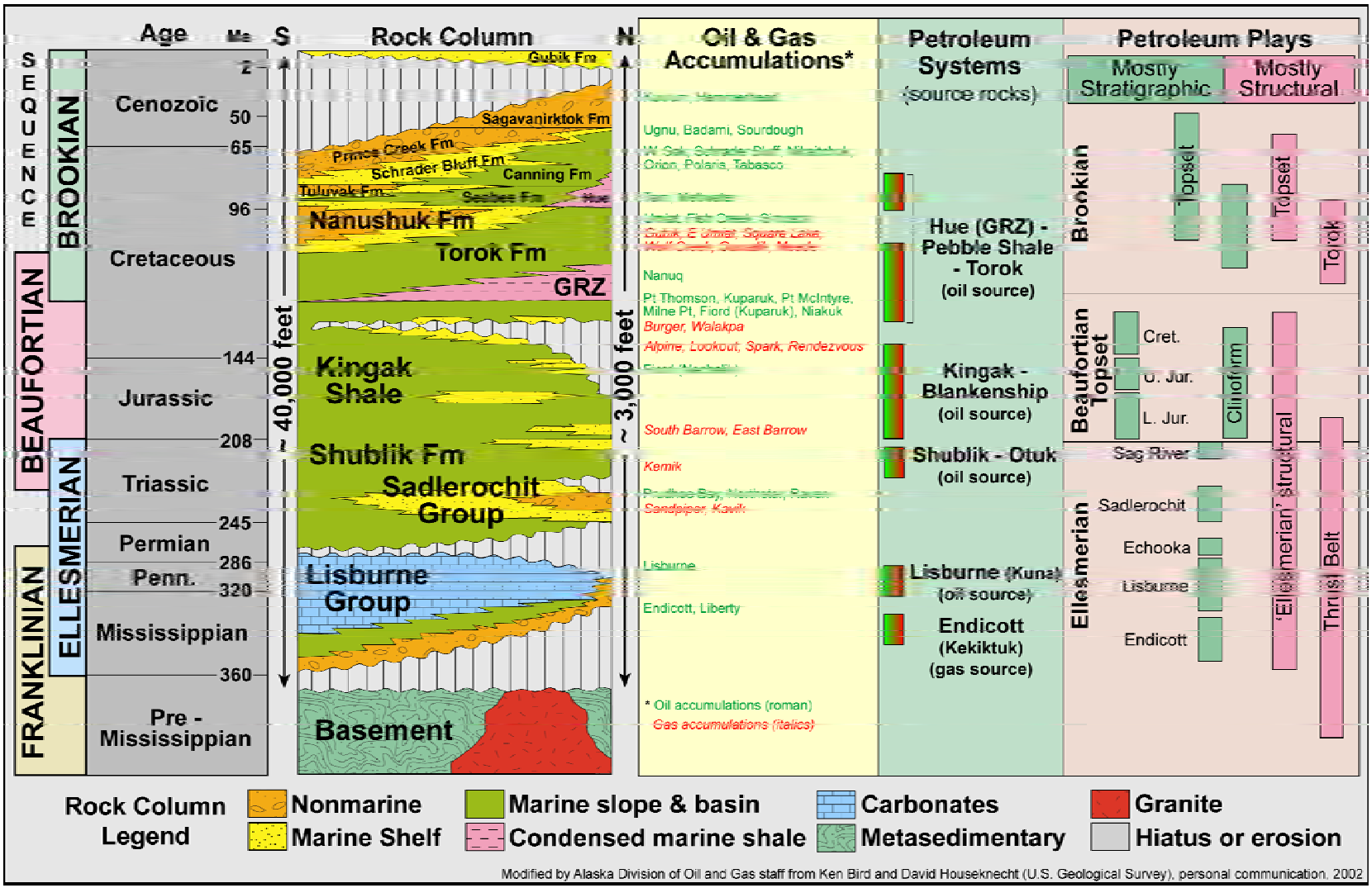
Era	Period	Epoch	Age (Millions of years)
Cenozoic	Quaternary	Holocene	0.01
		Pleistocene	1.8
	Tertiary	Pliocene	5.3
		Miocene	23.0
		Oligocene	33.9
		Eocene	55.8
		Paleocene	65.5
Mesozoic	Cretaceous	Early to Late	145.5
	Jurassic	Early to Late	199.6
	Triassic	Early to Late	251.0
Paleozoic	Permian	Early to Late	299.0
	Pennsylvanian	Early to Late	318.1
	Mississippian	Early to Late	359.2
	Devonian	Early to Late	416.0
	Silurian	Early to Late	443.7
	Ordovician	Early to Late	488.3
	Cambrian	Early to Late	542.0

Notes: Modified by DO&G staff from USGS 2007.

The Beaufortian sequence consists of marine shales, siltstones, and sandstones sourced from the Barrow Arch rift shoulder. Oil and gas accumulations adjacent to the Barrow Arch are contained in purely stratigraphic or combination structural/stratigraphic traps formed by associated rifting events; however, in the foothills proper, structural traps form the dominant play (Figure 6.2). The Beaufortian sequence contains proven oil and gas accumulations such as the Kuparuk, Point McIntyre, Milne Point, Fiord-Kuparuk, Niakuk, and Fiord-Nechelik oil fields and the East Barrow, South Barrow, and Walakpa gas fields. The Kingak Shale and pebble shale unit (informal name) are two of the most continuous rock units in this sequence (Figure 6.1).

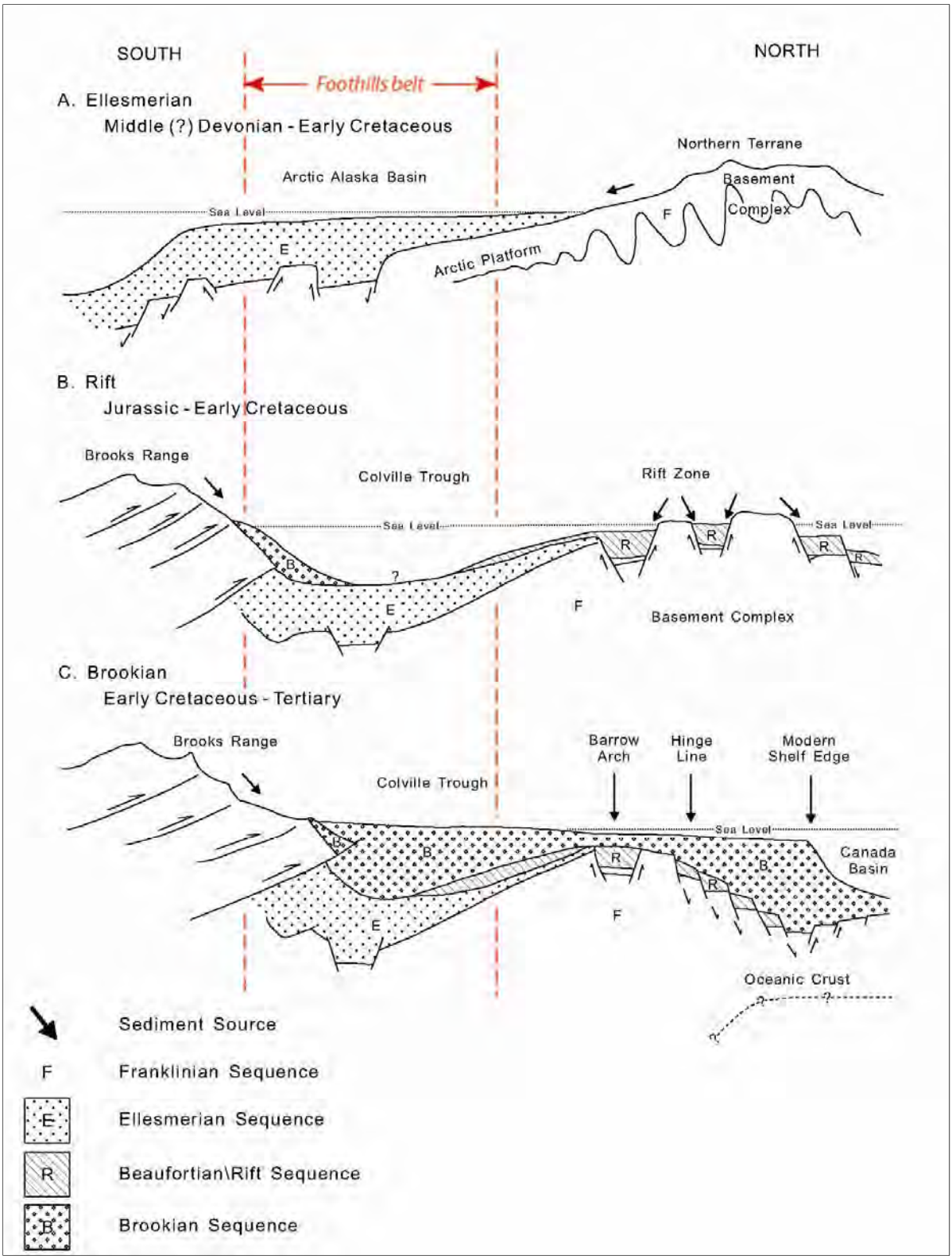
The Brookian sequence consists of sandstones that contain significantly less quartz and more ductile rock fragments than sandstones of the Ellesmerian sequence. Development of the Brookian sequence involved enormous amounts of sediment which were shed northward into the adjacent foredeep from the developing Brooks Range orogenic belt during Jurassic to Early Cretaceous time (Table 6.1). These sediments filled the Colville Basin to the north and then spread out over the Barrow Arch and onto the continental margin during Late Cretaceous to Tertiary time (Figure 6.2; Moore et al. 1994). The Brookian sequence contains proven oil and gas accumulations such as the West Sak, Schrader Bluff, Tabasco, Tarn, Meltwater, Umiat, Fish Creek, and Simpson oil fields and the East Umiat, Gubik, Square Lake, Wolf Creek, Oumalik, and Meade gas fields (Figure 6.1).

Refer to Map 5.9 and Map 5.10 for the location of the Gubik gas field, located north of and outside the lease sale area.



Source: USGS 2002.

Figure 6.1. Chronostratigraphic diagram for the central North Slope showing major sequences, discovered oil and gas accumulations, source rocks, and generalized plays.



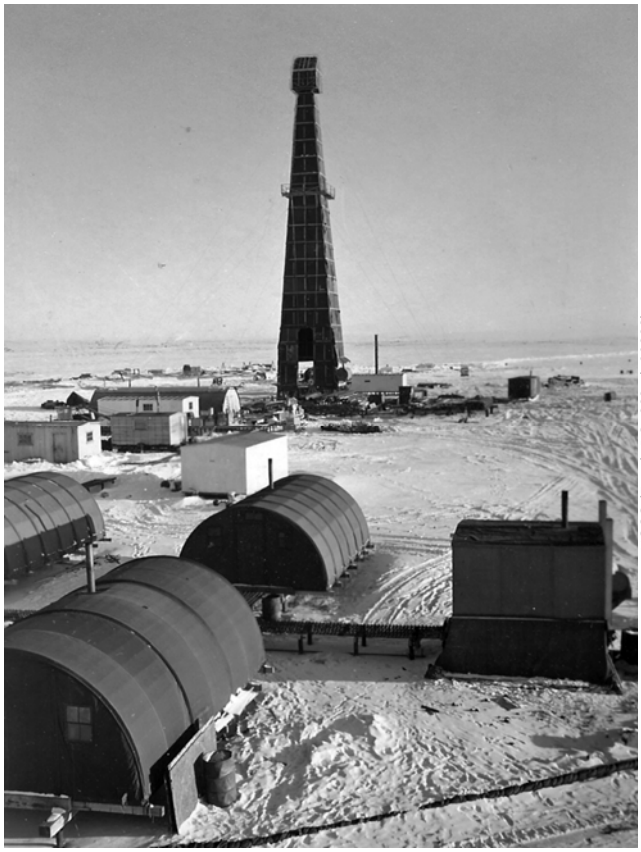
Source: Craig et al. 1985.

Figure 6.2. Schematic cross-sectional representation of North Slope basin evolution: Devonian time to present.

Petroleum source rock facies of the Shublik Formation, Kingak Shale, pebble shale unit, and Hue Shale (gamma ray zone) and younger basinal shales of the Brookian sequence (Figure 6.1) are all likely to have generated gas and/or oil within the NSFP, based on organic richness, kerogen composition, and thermal maturity determined from well and outcrop samples. The data suggest these rocks currently reside principally within the gas window and partially within the oil window (Bird 1994; Bird 2001; Peters et al. 2006).

B. Exploration History

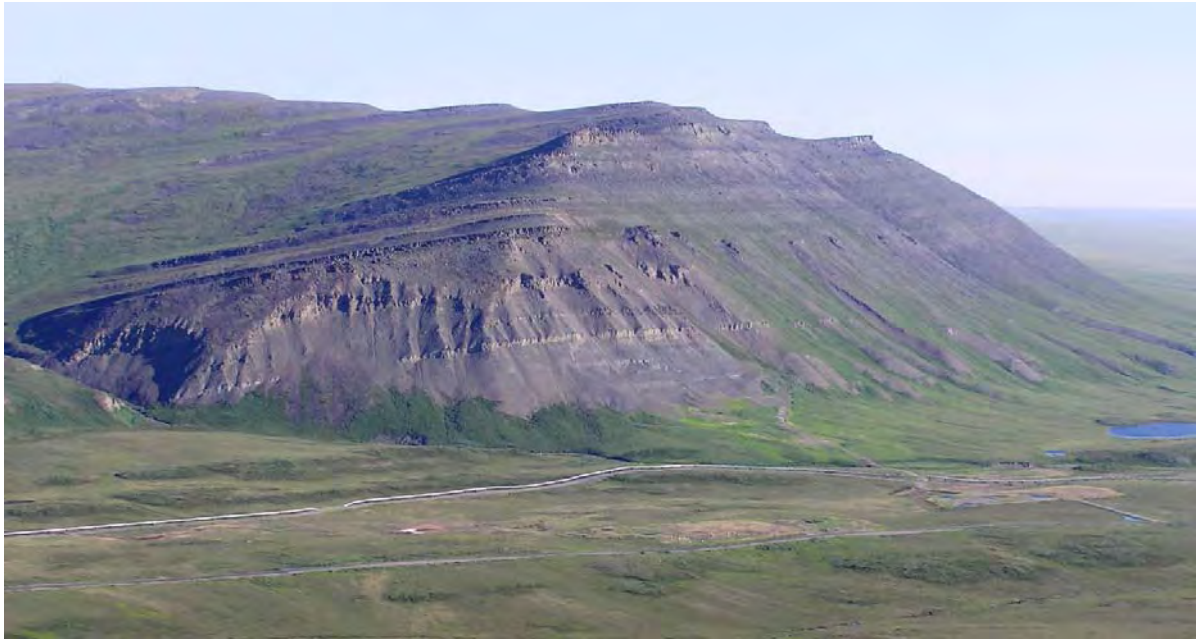
The NSFP on the northern flanks of the Brooks Range was considered prospective for hydrocarbon exploration as early as the 1920s because of widespread discernable surface anticlinal structures in the area. The U.S. Geological Survey (USGS) spent the summers of 1923-1926 conducting reconnaissance surface-mapping in the NSFP.



Meade River test well 1 derrick, April 17, 1950.

From 1944-1953 the U.S. Navy, in conjunction with the USGS, conducted a widespread exploration drilling program in an area of the North Slope known at the time as the National Petroleum Reserve No. 4 (NPR-4) and known today as the National Petroleum Reserve-Alaska (NPR-A) (Bird 1994). The southern part of this area includes a region that today falls within the northern part of the North Slope Foothills lease sale boundary and NSFP area. As a result of the NPR-4 drilling program oil accumulations were discovered at Fish Creek, Cape Simpson, and Umiat and gas accumulations were discovered at South Barrow, Simpson, Meade, Wolf Creek, and Gubik (Figure 6.1). The Umiat oil and Gubik gas accumulations are located near the westward bend in the Colville River and adjacent to, but outside of, the north-central part of the lease sale area.

Building on the exploration drilling efforts of the U.S. Navy, private industry began exploratory drilling in the mid 1960s. In 1964, six wells were drilled by various companies within the lease sale area. Drilling was focused where surface expressions indicated anticlinal structure, following the pattern set by the U.S. Navy. Although hydrocarbon shows were present in each of the six wells drilled, no oil fields and only one sub-commercial gas field (East Umiat) were identified as a result of this work. The East Umiat gas field is located in topset (shallow water) sandstones of the Nanushuk Formation within the Cretaceous aged Brookian sequence (Figure 6.1). A second pulse of exploratory drilling occurred from 1969-1971. Four wells were completed within the lease sale area during this time, but none led to any further activity. Although it lies outside of the North Slope Foothills lease sale boundary, the undeveloped Kavik gas accumulation occupies an anticlinal trap similar to other foothills structures, and was discovered in 1969.



P. Decker, DO&G 2007

Lower Cretaceous shelfal strata of the uppermost Torok Formation and nonmarine units of the Nanushuk Formation at Slope Mountain in the North Slope Foothills lease sale area.

From 1974-1982 eleven additional exploratory wells were drilled in the lease sale area. The East Kurupa Unit 1 well resulted in the discovery of the East Kurupa gas accumulation, which occurs near the base of the Brookian sequence in bottomset (deep water) sandstones assigned to the lower Torok Formation or the Fortress Mountain Formation (Figure 6.1). The undeveloped Kemik gas field, located east of the Dalton Highway near the Arctic National Wildlife Refuge in the foothills of the northeastern Brooks Range, is contained in fractured, low permeability rocks of the Triassic Shublik Formation belonging to the Ellesmerian sequence (Figure 6.1), the oldest stratigraphic series with commercial hydrocarbon significance in northern Alaska. The gas at Kemik is believed to have been sourced from organic rich shales and limestones of the Shublik Formation (Magoon et al. 2003), with minimal migration from kitchen to reservoir (refer to Section C, Petroleum Potential below for further discussion). The Lisburne 1 well, completed in 1980 by Husky, was drilled as part of the USGS-led NPR-A exploration program. The boundary of NPR-A was later adjusted in that area, and the Lisburne 1 well now lies just within the western boundary of the lease sale area. This well tested the hydrocarbon potential of the Lisburne carbonates on a closed anticlinal structure in the overthrust belt on the western edge of the NSFP and the lease sale area. Minor gas shows were encountered in poor reservoir-quality rocks throughout the well (Legg 1983). Chevron drilled three wells on Arctic Slope Regional Corporation (ASRC) land: the Tiglukpuk 1 well in 1978, the Killik 1 well in 1981, and the Cobblestone 1 well in 1981-1982.

The last wells drilled in the lease sale area were the Big Bend 1 well, drilled on ASRC land in 1993 by ARCO and the Chandler 1 well, drilled in 2008-2009 by Anadarko Petroleum Corporation. The Chandler 1 well targeted the flank of the East Umiat anticline and established the presence of a deeper bottomset (deep water) gas reservoir likely of the Torok Formation and/or Fortress Mountain Formation (Petroleum News 2009; OGJ 2009). The Gubik 3 and 4 wells were also drilled and completed in 2008-2009 by Anadarko Petroleum Corporation in the Gubik gas field north of the lease sale area (AOGCC 2010b).

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The southerly equivalent to the Upper Triassic Shublik Formation in the southern foothills.

C. Petroleum Potential

The potential for new discoveries of conventionally recoverable petroleum in the lease sale area, located in the NSFP is relatively high for gas, and relatively low for oil. Determining petroleum potential requires evaluation of the geology, geophysics, and exploration history of an area, which in this case requires analysis of data that are sparsely distributed and in many cases antiquated by today's standards, making it a difficult task.

With the exception of the Umiat oil accumulation, discoveries to date within the NSFP consist primarily of dry gas trapped in anticlinal fold closures, most of which were identified from early surface geologic mapping supported by two-dimensional reflection seismic surveys. This is strong evidence, corroborated by outcrop and well data, that many of the source rocks in the foothills have reached advanced thermal maturity due to deep sediment burial, and that major new oil finds are unlikely. On the basis of geochemical and stratigraphic evidence, the hydrocarbons in the accumulations west of the Dalton Highway are traced to Lower Cretaceous shale source rocks of the gamma ray zone and lower Torok Formation at the base of the Brookian sequence (Figure 6.1; Magoon et al. 2003). These western accumulations are reservoired in Brookian topset sandstones of the Nanushuk and Tuluvak Formations. These units are largely to entirely absent to the east of the Dalton Highway, though younger Brookian units are present that may have untapped potential.

A petroleum systems approach is useful for evaluating the undeveloped resource potential of areas such as the NSFP that have not yet reached an advanced stage of exploration. This methodology considers and quantifies each of the interdependent elements of the overall geologic framework that together create producible accumulations of oil and gas. There are three basic elements of functioning petroleum systems: *effective source rocks* to generate oil and gas in the thermally mature area of the basin (referred to as the petroleum "kitchen"), *effective reservoir rocks* with pore space to store them in, and *effective traps*, the sealed compartments that contain hydrocarbon fluids, preventing their escape. Each of these three components must be physically connected to the others at the *critical moment*, the brief episode during the system's geologic history when hydrocarbons are generated, migrate out of their source rock, and in favorable outcomes, encounter reservoirs in trapping configurations.

An important distinction must be drawn between *resources* and *reserves*. In North America, and most other countries, the term "reserves" is restricted to discovered, well-quantified, technically recoverable volumes that are nearly certain to reach commercial production. All other oil and gas, whether discovered or yet-to-be found, belongs in one of the various "resource" categories (Society of Petroleum Engineers 2005). In keeping with these definitions, oil and gas volumes discovered to date in the NSFP are currently best described as "sub-commercial resources" whose development potential is contingent upon constantly fluctuating economic factors and connection to markets.

Wellhead proximity to existing oil or gas infrastructure directly affects the size of the resource required to make a project economic. Due to the remoteness of the lease sale area from existing oil and gas infrastructure, any discovered resource needs to be of sufficient size to economically justify production. To date, this has not been the case. The State of Alaska is currently deliberating construction of a transportation corridor, called the Foothills West Transportation Project, connecting the Umiat and Gubik area to the Dalton Highway. ADOT is currently considering corridor alternatives that maximize the benefits for hydrocarbon exploration and development (ADOT 2009). It is anticipated that such a road would dramatically improve the likelihood of economically justifiable hydrocarbon development in the lease sale area.

D. Phases of Oil and Gas Development

Lease-related activities proceed in phases, moving from leasing, to exploration, development and production, transportation and storage, as needed. Each phase's activities depend on the completion or initiation of the preceding phase. Table 6.2 lists some activities that may occur during the exploration, development, and production phases.

1. Lease Phase

Oil and gas lease sales are the first step in developing the state's oil and gas resources. Annually, DO&G prepares and presents a 5-year program of oil and gas lease sales to the legislature. DO&G conducts competitive annual areawide lease sales, offering for lease all available state acreage within five areas: North Slope; Beaufort Sea; Cook Inlet; North Slope Foothills; and the Alaska Peninsula. The lease sale area is divided into tracts, and interested parties that qualify may bid on one or more tracts.

Not later than 45 days before the lease sale, DO&G issues a notice describing the interests to be offered, the location and time of the sale, and the terms and conditions of the sale (AS 38.05.035(e)(6)(F)(ii)). The announcement includes a tract map showing generalized land status, estimated tract acreages, and instructions for submitting bids. The actual lease sale consists of opening and reading the sealed bids and awarding a lease to the highest bid per acre by a qualified bidder on a tract. DO&G verifies the state's ownership interest only for the acreage within tracts that receive bids. Only those state-owned lands within the tracts that are determined to be free and clear of title conflicts are available to lease.

Alaska has several leasing method options designed to encourage oil and gas exploration and maximize state revenue. These methods include combinations of fixed and variable bonus bids, royalty shares, and net profit shares. Lease terms are set at 5, 7, or 10 years, depending on a number of factors, including geographical location. An oil and gas lease grants to the lessee the exclusive right to drill for, extract, remove, clean, process, and dispose of oil, gas, and associated substances. A lease plan of operations must be approved before most operations may be undertaken on or in the leased area.

Although beyond the scope of this best interest finding, exploration licensing supplements the state's areawide oil and gas leasing program by targeting areas outside of known oil and gas provinces. The intent of licensing is to encourage exploration in areas far from existing infrastructure, with relatively

low or unknown hydrocarbon potential, where there is a higher investment risk to the operator. Because bonus payments are required to win a lease, lease sales held in some of these higher-risk areas tend to attract little participation. Exploration licensing gives an interested party the exclusive right to conduct oil and gas exploration without this initial expense. Through exploration licensing, the state receives valuable subsurface geologic information on these regions and, should development occur, additional revenue through royalties and taxes (AS 38.05.131-134).

Table 6.2. Potential activities during exploration, development, and production phases

Exploration	Development	Production
Permitting	Gravel pits, pads, and roads	Well work over (rigs)
Water usage	Dock and bridge construction	Gravel islands, pads, and roads
Environmental studies	Drilling rigs	Produced water
Seismic acquisition	Pipelines	Air emissions
Exploratory drilling rigs	Work camps	Pipeline maintenance
Drilling muds and discharges	Permitting	Work camps
Gravel or ice road beds	Monitoring	Trucking
Work camp	Well heads	
Increased air traffic	Injection wells	
Temporary ice or gravel pads	Seismic acquisition	
Research and analysis		

2. Exploration Phase

During the exploration phase, information is gathered about the petroleum potential of an area by examining surface geology, researching data from existing wells, performing environmental assessments, conducting geophysical surveys, and drilling exploratory wells. The surface analysis includes the study of surface topography or the natural surface features, and near-surface structures revealed by examining and mapping near-by exposed rock layers. Geophysical exploration and exploration drilling are the primary activities that could result in potential effects to the North Slope Foothills lease sale area. Geophysical surveys, primarily seismic, help reveal the characteristics of the subsurface geology.

a. Geophysical Exploration

Before proceeding with geophysical exploration, companies must acquire one or more permits from the state, depending on the timing and extent of the proposed activity. Geophysical exploration activities are regulated by 11 AAC 96. DO&G evaluates each permit and issues an authorization relating to the specifics of the proposed project. Restrictions on geophysical exploration permits depend on the duration, location, and intensity of the project. They also depend on the potential effects the activity may have on fish and wildlife resources or human use in the area. The extent of potential effects varies, depending on the survey method and the time of year the survey is conducted.

Seismic surveys are the most common type of geophysical exploration, and are typically conducted by geophysical companies under contract to leaseholders or as multi-client and speculative surveys run directly by the seismic contractors. At the survey location, energy is emitted into the subsurface and reflected seismic waves are recorded at the surface by geophones and/or hydrophones, vibration-sensitive devices. Different rock layers beneath the surface have different velocities and densities. This results in a unique seismic profile that can be analyzed by geophysicists to interpret subsurface

Courtesy PGS

Active seismic work on the North Slope.

structures and petroleum potential. Both 2-dimensional (2D) and 3-dimensional (3D) data are gathered from seismic surveys.

Seismic source and receiver locations are surveyed using GPS (Global Positioning Systems) and laid out or sailed in predesigned patterns. For land or ice 2D data, the receivers and sources lie in a straight line (as topographic and ice conditions permit), and can extend for many tens of miles. For 3D data, data is collected over a much wider swath, and can cover tens to hundreds of square miles. 2D seismic programs usually have fewer crew members and employ much less equipment than 3D programs.

Seismic data can be collected after the ground is well frozen and covered with a protective snow layer. Seismic in shallow water can be collected on the ice in winter, or by using bottom cables in the summer months. Ice based seismic programs are dependent on ice thickness and stability. Collecting data in the winter months may minimize effects to fish and wildlife habitats, and avoids conflicts with migrating marine mammals.

Multiple seismic sources can be used on land or ice surveys, but vibrator trucks are by far the most common. A vibrator truck is a low ground pressure vehicle with a heavy plate attached. The entire weight of the truck rests on the plate as it puts energy of continuously varying frequency into the ground. The vibration typically lasts 4 to 16 seconds. This energy source is less destructive than an impulsive explosive source, where all the energy is imparted in an instant. Less commonly, air guns can be lowered through holes drilled in the ice to provide the acoustic energy.

Additional geophysical techniques can be used to gather information specifically about very near surface geology, usually to identify drilling hazards. They include high-resolution shallow seismic, side-scan sonar, fathometer recordings and shallow coring programs. High-resolution shallow seismic surveys are specifically designed to image the bottom of the water body and very shallow geology. They employ a lower energy seismic source and a shorter cable than surveys targeting deeper oil and gas potential.

b. Exploration Drilling

Exploratory drilling often occurs after seismic surveys are conducted, and when the interpretation of the seismic data incorporated with all available geologic data indicates possible oil and gas prospects. Exploration drilling, which proceeds only after obtaining the appropriate permits, is the only way to learn whether a prospect contains commercial quantities of oil or gas, and aids in determining whether to proceed to the development phase. Drilling operations collect well logs, core samples, cuttings, and a variety of other data. A well log is a record of one or more physical measurements as a function of depth in a borehole and is achieved by lowering measuring instruments into the well bore. Well logs can also be recorded while drilling. Cores may be cut at various intervals so that geologists and engineers can examine the sequences of rock that are being drilled.

The drilling process generally proceeds as follows:

- Large diameter steel pipe (conductor casing) is bored into the soil.
- A drill bit, connected to the end of the drill pipe, rotates and drills a hole through the rock formations below the surface.
- After a prescribed depth of drilling, the hole is cleaned up and surface casing, a smaller diameter steel pipe, is lowered into the hole and cemented in place. This keeps the hole from caving in; seals off rock formations; seals the well bore from groundwater; and provides a conduit from the bottom of the hole to the drilling rig.
- After surface casing is set, drilling continues until the objective formation is reached. In instances where subsurface pressures are extremely high, an intermediate casing string may be lowered into the hole and cemented in place.
- The well either: produces; is suspended; or is plugged and abandoned.

The drill site is selected to provide access to the prospect and, if possible, is located to minimize the surface area that may have to be cleared. Sometimes temporary roads must be built to the area. Non-permanent roads are constructed of ice, with permanent roads being constructed of sand and gravel placed on a liner above undisturbed ground. Construction of support facilities such as production pads, roads, and pipelines may be required. A typical drill pad is made of ice or sand and gravel placed over a liner and is about 300 ft by 400 ft. The pad supports the drill rig, which is brought in and assembled at the site, a fuel storage area if necessary, and a camp for workers. If possible, an operator will use nearby existing facilities for housing and feeding its crew. If facilities are not available, a temporary camp of trailers on skids may be placed on the pad. Enough fuel is stored on-site to satisfy the operation's short-term needs. The fuel storage area is a diked gravel pad lined with an 80 mil synthetic membrane. Additional amounts of fuel may be stored at the nearest existing facility for transport to the drilling area as needed (Chevron 1991).

Directional drilling is used to extend the length of the reservoir that is penetrated by the well (Dawe 2001). Exploration wells within the lease sale area may be directionally drilled because of a lack of suitable surface locations directly overlying exploration targets. The drilling technique used is controlled to direct the bore hole to reach a particular part of the reservoir. Directional drilling technology enables the driller to steer the drill stem and bit to a desired bottom hole location. Directional wells initially are drilled straight down to a predetermined depth and then gradually curved at one or more different points to penetrate one or more given target reservoirs (Van Dyke 1997). Directional drilling also allows multiple production and injection wells to be drilled from a single surface location such as a gravel pad or offshore production platform, thus minimizing cost and the surface impact of oil and gas drilling, production, and transportation facilities. It can be used to reach a target located beneath an environmentally sensitive area and may offer the most

economical way to develop offshore oil fields from onshore facilities. Extended reach drilling (ERD) is used to access reservoirs that are remote (up to 10 km) from the drilling location. These techniques allow for drilling into reservoirs where it is not possible to place the drilling rig over the reservoir (Dawe 2001).

An exploratory drilling operation generates drilling cuttings, that are fragments of rock cut by the drill bit. These fragments are carried up from the drill bit by the mud pumped into the well (Van Dyke 1997). Gas, formation water, fluids, and additives used in the drilling process are also produced from drilling operations. The fluids pumped down the well are called "mud" and are naturally occurring clays with small amounts of biologically inert products. Different formulations of mud are used to meet the various conditions encountered in the well. Chemicals may be added to maximize the effectiveness of drilling and casing. Drilling additives may include petroleum or other organic compounds to modify fluid characteristics during drilling (Lapham et al. 1997). Additives may be aromatic hydrocarbons, emulsifiers and metals (Woodward et al. 1988). Oil-based muds and synthetic-based muds may also be used, depending on the well depth, well diameter, and subsurface formations (NRC 1983; Veil et al. 1996). Muds are used to cool and lubricate the drilling bit, to prevent the drill pipe from sticking to the sides of the hole, to facilitate the drilling action, to carry cuttings within the well bore to the surface, to seal off cracks in down-hole formations to prevent the flow of drilling fluids into these formations, and to maintain reservoir pressure.

During drilling and after a well is in production, produced water comes to the surface mixed with oil and gas and must be separated before further refining. Drilling muds, fluids, and cuttings produced from the well are separated and disposed of, often by reinjection into an approved disposal well annulus or disposal well, or they may be shipped to a disposal facility out-of-state. Produced waters are reinjected either into the producing formation to enhance recovery, or into an injection well.

Disposal of mud, cuttings, and other effluent from the oil and gas industry is regulated by the National Pollutant Discharge Elimination System (NPDES) and the EPA's Underground Injection Control program (UIC), administered by the Alaska Oil and Gas Conservation Commission under AS 31.05 and 20 AAC 25. During exploration well drilling, muds and cuttings are stored on-site, in holding tanks, or in a temporary reserve pit, and then hauled to an approved solid waste disposal site, or are reinjected into the subsurface at an approved injection well, in accordance with 20 AAC 25.080 and 20 AAC 25.252. The preferred method for disposal of drilling muds and cuttings is by underground injection, and production muds and cuttings on the North Slope are generally reinjected into a Class II injection well.

The state discourages the use of reserve pits, but if a reserve pit is necessary and approved, it is constructed off the drill pad and could be as large as 5 ft deep and 40 ft by 60 ft. It is lined with an 80-mil geotextile liner to prevent contamination of surrounding soils. Impermeable lining and diking, or equivalent measures, will be also required. With appropriate permits, solids may be left in place in a capped reserved pit. If necessary, a flare pit may be constructed off the drill pad to allow for the safe venting of natural gas that may be encountered in the well. New solid waste disposal sites will not be approved or located on state property during the exploration phase.

If oil or gas is discovered at the exploratory well, it is likely that the gravel pad used for the exploratory well will also be used for development and production operations. Gravel pads are semi-permanent structures and can be rehabilitated following field depletion.

3. Development and Production Phases

a. Overview

The development and production phases are interrelated and overlap in time; therefore, this section discusses them together. Development and production phases can begin only after exploration has been completed and tests show that a discovery is economically viable (Van Dyke 1997). During the

development phase, operators evaluate the results of exploratory drilling and develop plans to bring the discovery into production. Production operations bring well fluids to the surface and prepare them for transport to the processing plant or refinery. The fluids undergo operations to purify, measure, test and transport. Pumping, storage, handling, and processing are typical processes in the production phase (Van Dyke 1997).

After designing the facilities and obtaining the necessary permits, the operator constructs permanent structures and drills production wells. The operator must build production structures that will last the life of the field and may have to design and add new facilities for enhanced recovery operations as production proceeds. Figure 6.3 depicts a typical wellbore. The development "footprint" has decreased in size in recent years as advances in drilling technology have led to smaller, more consolidated pad sizes. Directional drilling allows more wells to be drilled from a common location (drill pad). A single production pad and several directionally drilled wells can develop larger subsurface areas, as compared to the techniques of drilling multiple vertical wells to reach the same subsurface areas.

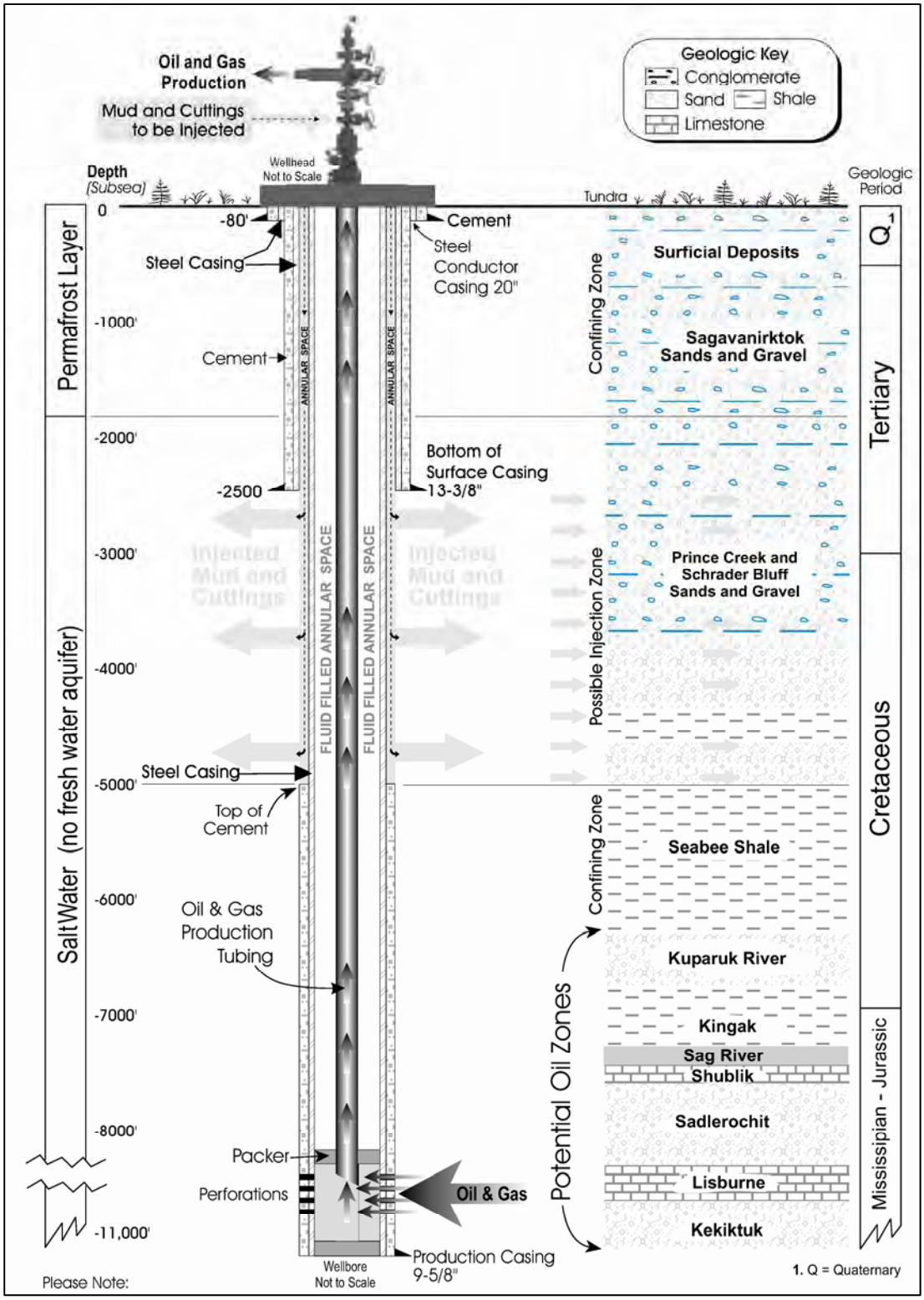
DO&G Permitting Staff

CD3 pipeline under construction at Prudhoe Bay.

Development wells are often drilled at an angle through a formation to increase productivity and allow the oil and gas to be extracted from a larger subsurface area (by increasing the drainage area) than would be possible from a single straight wellbore. In addition, lateral bores may be drilled from one "parent" well bore to penetrate separate sands within a reservoir and increase the area of reservoir exposed to production. Multiple laterals, up to five, have been drilled to improve drainage and productivity. This technique is especially effective in the heavier viscous oil accumulations.

Production facilities will likely include several production wells, water injectors, gas injection wells, and a waste disposal well. Wellhead spacing may be as little as 10 ft. A separation facility removes water and gas from the produced crude, and pipelines carry the crude to storage and terminal facilities. Some of the natural gas produced is used to power equipment on the well pad or processing facility, but most is reinjected to maintain reservoir pressure in those reservoirs that have a surplus of produced gas. Produced water is also reinjected into an oil producing formation to maintain reservoir pressure. Often, seawater is treated and injected into the reservoir in addition to produced water in order to maintain pressure, improve recovery, and replace produced fluids.

Production muds and cuttings on the North Slope are reinjected into a Class II injection well. Produced waters are reinjected either into the producing formation to enhance recovery, or into an injection well. The preferred method for disposal of drilling muds and cuttings from oil and gas activities is by underground injection, as administered in the Underground Injection Control (UIC) program by AOGCC. When approved, impermeable lining and diking, or equivalent measures, will be required for reserve pits.



Notes: When injection phase is completed, the 9-5/8" X 13-3/8" annular space is pumped full of cement and permanently sealed.

Figure 6.3. Typical production/injection well, North Slope, Alaska.

Oil and gas production facilities found on the well site may include gas and oil processing facilities to remove some of the water produced with the petroleum, water and sewage treatment equipment, power generators, a drilling rig, and support buildings and housing for workers. Support facilities include a production facility to receive and treat or transport the oil and gas to markets, refineries, or for shipment to other processing facilities in the lower 48 states and elsewhere. Other support facilities may include a supply base and a transportation system for cement, mud, water, food, and other necessary items.

Production operations for natural gas generally follow these steps:

- Natural gas flows through a high-pressure separator system where any liquids (water, condensate, etc.) are removed. Produced oil goes through a separator to remove the natural gas from the oil.
- The gas is compressed if necessary.
- The gas is dehydrated to lower its water content.
- Impurities are removed, if necessary.
- The gas is then metered, i.e. the amount of gas produced is measured.
- The gas is transported to an onshore facility where it passes through a water precipitator to remove any liquid.
- The gas may be conditioned or treated prior to transportation. An example is the conversion of gas to liquefied natural gas.

Production operations steps for oil are:

- Produced crude oil goes through a separator to remove water and gas from the oil stream.
- The oil moves to a processing facility via a pipeline.
- The gas removed from the oil may be used to power production facilities or compressed and reinjected to keep the pressure up in the producing formation to assist in oil production.

AOGCC through its statutory and regulatory mandate oversees drilling and production practices to maximize oil and gas recovery, prevent waste and ensure protection of correlative rights within the state (AS 31.05, 20 AAC 25). Correlative rights are legal rights to protect resource owners from excessive or wasteful withdrawal of hydrocarbons by adjoining properties overlying the same oil and gas reservoir (Answerscom 2010). The AOGCC is a quasi-judicial agency, which conducts hearings to review drilling and development to ensure regulatory compliance. The AOGCC may issue Conservation Orders (pool rules) to grant exceptions to regulations conditioned on prevention of waste, maximizing ultimate oil and gas recovery. Unless pool rules (oil or gas field rules governing well drilling, casing, and spacing that are designed to maximize recovery and minimize waste) have been adopted under 20 AAC 25.520, existing spacing rules stipulate that where oil has been discovered, not more than one well may be drilled to that pool on any governmental quarter section (20 AAC 25.055(a)). This would theoretically allow a maximum of four well sites per 640-acre section.

Where gas has been discovered, not more than one well per section may be drilled into the pool. An oil and gas producer may apply to change the spacing requirements if there is technical justification to support greater ultimate recovery by changing the spacing requirements. A Conservation Order will grant exception to regulations under 20 AAC 25 upon finding and concluding the spacing exception will not cause waste.

b. Proposed Development in the North Slope Foothills

The last wells drilled in the NSFP were the Big Bend 1 well, drilled on ASRC land in 1993 by ARCO and the Chandler 1 well, drilled in 2008-2009 by Anadarko Petroleum Corporation. These wells targeted the flank of the East Umiat anticline and established the presence of a deeper bottomset (deep water) gas reservoir likely of Torok Formation and/or Fortress Mountain Formation (Petroleum News 2009; OGJ 2009; Figure 6.2).

The Gubik well 3 was also drilled by Anadarko Petroleum Corporation in the Gubik gas field to the north of the lease sale area, and was completed in April, 2008 (AOGCC 2010b). This well is located north of the northwest portion of the lease sale area on land owned by ASRC.

Existing oil fields on the North Slope also contain considerable amounts of gas that may be extracted and transported to market in the future. Tapping the North Slope's and the North Slope Foothill's gas reserves may require additional facilities, wells, and a new pipeline system.

At the best interest finding phase it is impossible to predict what a full development scenario will entail. The final project parameters will depend on the surface location, size, depth, and geology of a specific commercial discovery.

4. Subsurface Oil and Gas Storage Phase

Under AS 38.05.180(u), the Commissioner of ADNR may authorize the subsurface storage of oil or gas to avoid waste or to promote conservation of natural resources. In Alaska, depleted reservoirs with established well control data are preferred storage zones. By memorandum dated September 2, 2004, the Commissioner approved a supplement to Department Order 003 and delegated the authority to authorize subsurface storage of oil or gas to the Division of Oil and Gas Director.

Subsurface storage of gas increases reliability of gas delivery to all sources of demand. The need for gas storage also depends upon access to transportation, pipeline infrastructure, existing production infrastructure, gas production sources, and delivery points. A subsurface storage authorization allows the storage of gas and associated substances in the portions of the gas storage formation, subject to the terms and applicable statutes and regulations, including mitigation measures and advisories incorporated by reference into the authorization. It does not matter whether the oil or gas is produced from state land, so long as storage occurs in land leased or subject to lease under AS 38.05.180. An oil and gas lease on which storage is authorized shall be extended at least for the period of storage and so long thereafter as oil or gas not previously produced is produced in paying quantities. The feasibility of subsurface storage depends on favorable geological and engineering properties of the storage reservoir, including its size and its cushion gas (or base gas requirements). Some unproduced native gas may remain in gas storage reservoirs as cushion gas to maintain reservoir pressures. Cushion gas is the volume of gas intended as permanent inventory in a storage reservoir to maintain adequate pressure and deliverability rates throughout the gas withdrawal season.

Subsurface storage must comply with all applicable local, state, and federal statutes and regulations, and with any terms imposed in the authorization or in any subsequent plan of operation approvals, or in the AOGCC Storage Injection Order. The plans of operation must identify the specific measures, design criteria, construction methods, and standards that will be employed to meet the provisions of the subsurface storage authorization. Plans of operation are subject to extensive technical agency review. They are also subject to consistency with the ACMP standards if the affected lands are within the coastal zone. The plans are available for public review upon submittal to the state. Oil and gas storage-related activities will be permitted only if proposed future operations comply with all borough, state, and federal laws and the provisions of the authorization.

A storage authorization is for only specified sand horizons and does not grant the right to drill, develop, produce, extract, remove, or market gas other than injected gas. A storage authorization allows the overlying oil and gas leases to continue as long as their original terms are met. Subsurface storage will be subject to terms and conditions identical to existing oil and gas lease permitting and bonding requirements. Storage operations may not interfere with existing oil and gas lease operations. Subsurface storage must comply with 20 AAC 25.252. Before any gas may be injected, approval of the Injection Order from AOGCC must be obtained.

Royalty on cushion gas may be paid from a percentage of each year's annual gas withdrawal as if it were originally produced from the overlying oil and gas lease, and allocated according to the unit agreement. Injected gas will mix with native gas in the reservoirs. Royalty on the native gas within the gas storage formation under the leased area is computed at the royalty rate and paid at the value as specified in the applicable oil and gas leases.

5. Activity Subsequent to Lease Sales

Upon issuance of oil and gas leases, exploration drilling may occur on tracts leased in this sale within the initial term of the lease. However, whether or not exploration and eventual development will occur in areas of the North Slope Foothills depends on several factors, such as the subsurface geology of the area, a company's worldwide exploration strategy, the projected price of oil and gas and their market demand, and other economic, environmental and logistical factors. Geology dictates the extent of exploration. Several dry holes (no substantial hydrocarbons encountered) can discourage further exploration in an area. Whether a lessee proceeds with exploration of an area may depend on the area's priority when weighed against the lessee's other worldwide commitments. If extensive exploration does occur in an area, and an accumulation is discovered, development and production will only proceed if the lessee finds the risks acceptable, given the potential costs. This depends on the price of oil and gas, the lessee's development costs, and the cost of getting the oil and gas to market.

6. Oil and Gas Infrastructure

The North Slope hosts an extensive network of petroleum production, development, and support facilities. The oil produced is transported to the TAPS gathering facility, into the pipeline, and, ultimately, to the TAPS terminal in Valdez. Prudhoe Bay continues to function as the hub of activity for the 14 active production units on the North Slope and in the Beaufort Sea, extending outward via roads, pipelines, production and processing facilities, gravel mines, and docks (ADNR 2010b). Deadhorse is comprised of an industry-support community that includes a post office and airport.

As exploration and development have continued, oil companies and regulatory agencies have capitalized on technological advances and existing infrastructure, thus minimizing environmental impacts on the North Slope.

If economically feasible quantities of natural gas are found and produced in the North Slope Foothills lease sale area, additional pipeline and processing infrastructure will probably need to be constructed.

7. Oil and Gas Lease Sales in the North Slope Foothills

Many factors contribute to the outcome of oil and gas lease sales in Alaska. These include national and world economies, exploration budgets of oil and gas companies, oil and gas potential of the area, technological advances, the number of tracts available for lease, and the number of expired and relinquished tracts.

Since the first lease sale in the northern region (Sale 13) in December 1964, the state has held 10 oil and gas lease sales involving North Slope Foothills. As of September 23, 2010, there are 114 tracts

leased in the lease sale area, for a total of 577,754 acres (ADNR 2010a). There are no reports of recent exploration or developments drilled on these tracts since 2001. The most recent well drilled in the area was Gubik well 3 in early 2008 by Anadarko Petroleum Corporation, and was not drilled on state owned land.

E. Likely Methods of Oil and Gas Transportation

AS 38.05.035(g) directs that best interest findings shall consider and discuss the method or methods most likely to be used to transport oil or gas from the lease sale area, and the advantages, disadvantages, and relative risks of each.

The location and nature of oil or gas deposits determine the type and extent of facilities necessary to develop and transport the resource. Strategies used to transport potential petroleum resources depend on many factors, most of which are unique to an individual discovery. ADNR and other state, federal, and local agencies will review the specific transportation system when it is actually proposed. Oil and gas produced in the lease sale area would most likely be transported by pipeline, depending on the type, size, and location of the discovery. The following is a general discussion of the components that might be in any transportation system.

1. Pipelines or Pipeline Facility

A "pipeline" or "pipeline facility" means all the facilities of a total system of pipe, whether owned or operated under a contract, agreement, or lease, used by a carrier for transportation of crude oil, natural gas, or products for delivery, for storage, or for further transportation. This includes all pipe, pump or compressor stations, station equipment, tanks, valves, access roads, bridges, airfields, terminals and terminal facilities, including docks and tanker loading facilities, operations control center for both the upstream part of the pipeline and the terminal, tanker ballast treatment facilities, and fire protection system, communication system, and all other facilities used or necessary for an integral line of pipe, taken as a whole, to effectuate transportation, including an extension or enlargement of the line. (AS 38.35.230 (7)). The mode of transport from a natural gas discovery will be an important factor in determining whether future discoveries can be economically produced.

If commercial quantities of oil are found in the lease sale area, the oil will likely go to market via the Trans-Alaska Pipeline System (TAPS), a 798-mile pipeline from Prudhoe Bay to Valdez. In-field gathering lines bring the oil from individual well sites to processing facilities for injection into TAPS. From Valdez, the oil is transported to the U. S. West Coast, and the U. S. Gulf Coast via tanker.

If commercial quantities of natural gas are found there are currently at least six possible gas pipeline routes under consideration by the Federal Energy Regulatory Commission (FERC):

1. A pipeline from the Alaska North Slope (both the foothills of the Brooks Range and the Prudhoe Bay area) to the tidewater in Cook Inlet, along the Parks Highway;
2. A pipeline from the Alaska North Slope to tidewater in Cook Inlet, along the Richardson & Glenn Highways;
3. A spur-line off a main-line to Alberta, Canada, down the Parks Highway to Cook Inlet; and
4. A spur-line off a main-line to Alberta, Canada, down the Glenn and Richardson Highways to Cook Inlet (FERC 2009).
5. A TransCanada Alaska LLC, and partner Exxon Mobil, applied for approval of a pipeline system and gas treatment plant originating near Prudhoe Bay, Alaska, including a 48-inch diameter pipeline designed to carry 4.5 billion cubic feet of natural gas per day. The open season plan, dated January, 2010, offered a pipeline system originating from the Alaska North

Slope near Prudhoe Bay with a pipeline mainline route to the Alberta Hub in Canada, with a second routing option to transport gas to Valdez, Alaska, to connect to a liquefied natural gas facility operated by a third party, the Alaska Gasline Port Authority. FERC approved the plan on March 31, 2010, and TC Alaska commenced its open season April 29, 2010. Results of the open season have not yet been released to the public. The State of Alaska has issued a license under the Alaska Gasline Inducement Act (AGIA) to TransCanada Alaska LLC to pursue construction of a natural gas pipeline. (FERC 2010).

6. A Denali – the Alaska Gas Pipeline project has been applied for approval by partners BP and ConocoPhillips. This proposed pipeline system and gas treatment plant originate near Prudhoe Bay, Alaska, and include a pipeline designed to carry 4.5 billion cubic feet of natural gas per day. The open season plan, dated April 7, 2010, offered a configuration of two transmission lines, one originating from Point Thomson, and a second originating from the Prudhoe Bay Unit on the North Slope, both connecting to a gas treatment facility at Prudhoe Bay Unit. A mainline pipeline system will then transport gas along a 730-mile long, 48-inch diameter pipeline to the international border between Alaska and Canada, with five delivery points along the route. FERC approved the plan on June 7, 2010, and Denali commenced its open season on July 2, 2010. Results of the open season have not yet been released to the public (FERC 2010).

Although BLM has conducted oil and gas lease sales in NPR-A, it has imposed a 10-year deferral of leasing in the area north and east of Teshekpuk Lake. Securing permits for siting oil and gas facilities in NPR-A will require an EIS; siting facilities in ANWR is unlikely to be approved. The status of ANWR could change if Congress amends federal law to permit petroleum exploration and development or if the Secretary of Interior allows a pipeline right-of-way. However, this transportation discussion is based on the assumption that ANWR will not be available for onshore support of a transportation system.

Jurisdictional authority over pipelines depends on many factors such as design, pipe diameter, product transported, or whether it meets state or federal designation, e.g., transmission line, gathering line, or distribution line, and other attributes as specified in regulations. Generally, the design, maintenance, and preservation of transmission pipelines transporting hydrocarbon products are under the authority and jurisdiction of the Pipeline and Hazardous Materials Safety Administration (PHMSA) with specific federal regulations for natural gas (49 CFR 192) and hazardous liquids (49 CFR 195). Both regulations prescribe the minimum requirements that all operators must follow to ensure the safety of their pipelines and piping systems. The regulations not only set requirements, but also provide guidance on preventive and mitigation measures, establish time frames for upgrades and repairs, development of integrity management programs, and incorporate other relevant information such as standards, incorporated by reference, developed by various industry consensus organizations.

On December 29, 2006, the "Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006" (PIPES Act H.R. 5782) was signed into law. The PIPES Act issued a final rule requiring hazardous liquid pipeline operators to develop integrity management programs for transmission pipelines.

Basic requirements for an Integrity Management Plan include:

- Periodic integrity assessment of pipelines that could affect high consequence areas (HCAs). Integrity assessments are performed by in-line inspection (also referred to as "smart pigging"), hydrostatic pressure testing, or direct assessment. Through these assessment methods, potentially injurious pipeline defects that could eventually weaken the pipe, or even cause it to fail, are identified early and can be repaired, thus improving the pipe's integrity.
- Development and implementation of a set of safety management and analytical processes, collectively referred to as an integrity management program (IMP). The purpose of the

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Trans Alaska Pipeline in the northern Brooks Range.

program is to assure pipeline operators have systematic, rigorous, and documented processes in place to protect HCAs (PHMSA 2010a).

- Integrity management programs reflect significant improvements to pipeline safety and have unique aspects depending on service characteristics for natural gas and liquid hydrocarbons.
- For gas pipelines, the Gas Transmission IM Rule (49 CFR 192, Subpart O) the "Gas IM Rule," as it is commonly referred to, became effective in February 2004, and represents a significant enhancement to PHMSA's existing pipeline safety regulations. The Gas IM Rule specifies how pipeline operators must identify, prioritize, assess, evaluate, repair, and validate - through comprehensive analyses - the integrity of gas transmission pipelines that, in the event of a leak or failure, could affect High Consequence Areas (HCAs) within the United States. These HCAs include certain populated and occupied areas. The framework for an integrity management system are covered in Subpart O - Gas Transmission Pipeline Integrity Management (49 CFR 192.907) and integrity program elements are in 49 CFR 192.911, which invoke ASME/ANSI B31.8S by reference (PHMSA 2010a).
- For liquid hydrocarbon (oil and product) pipelines, the mandate is for Pipeline Integrity Management programs to establish High Consequence Areas (HCA) for Hazardous Liquid Operators (49 CFR 195.450 and .452). The "Liquid IM Rule," as it is commonly referred to, represents a significant enhancement to PHMSA's existing pipeline safety regulations. The Liquid IM Rule specifies how pipeline operators must identify, prioritize, assess, evaluate, repair, and validate-through comprehensive analyses—the integrity of hazardous liquid pipelines that, in the event of a leak or failure, could affect HCAs within the United States. These HCAs include population areas, drinking water and ecological resources that are unusually sensitive to environmental damage, and commercially navigable waterways.

2. Oil Transportation

Feeder pipelines may be constructed to TAPS for oil transport. These are either elevated or buried depending on several factors such as the substance being transported, the local soil and ice conditions and other considerations such as movement of wildlife. An individual pipeline may

alternate between buried and elevated, as is the case with TAPS. The advantages and disadvantages of the two options are set forth below. It is possible that a transportation system used for oil or gas from the lease sale area would be based upon both options. The mode of transport from a discovery will be an important factor in determining whether or not discoveries can be economically produced. Buried pipelines are more expensive to install and maintain than elevated pipelines. The more expensive a given transportation option, the larger a discovery will have to be for economic viability.

a. Elevated Pipelines for Oil Transport

Elevated pipelines are essentially a series of support members or bridges that support a pipeline, and have the least potential to interfere with lateral fish movements or water circulation (USACOE 1984). Elevated pipelines allow visual monitoring for leaks and maintenance checks, are easy to maintain and visually inspect. Soil conditions are less of a limiting factor because pilings can be driven through problem soils; and heat transfer to thaw-unstable soils is minimized because the pipeline is not buried.

Elevated pipelines are typically used in North Slope oil field development to prevent heat transfer from the hot oil in the pipeline to frozen soils, since heat would degrade the permafrost. The pipeline is placed on crossbeams mounted between pairs of vertical support members (VSM). Heat pipes cool the ground to keep the soils stable (Van Dyke 1997). Above-ground pipelines can restrict caribou and other wildlife movements unless provisions are made to allow for their unimpeded passage. The current pipeline construction mitigation measures require that pipelines shall be elevated 7 ft except where the pipeline intersects a road, pad, or a ramp installed to facilitate wildlife passage; Refer to Mitigation Measure A(1)(g) (ADNR 2009b). There appears to be a cumulative effect of roads and adjacent pipelines that creates a barrier to caribou crossing (See Chapter Eight, "Foreseeable Effects"). Pipelines elevated at least 5 ft have been shown to be effective except when they were in proximity to roads with moderate to heavy traffic (15 or more vehicles/hour). Roads with low levels of traffic and no adjacent parallel pipeline are not significant barriers to movement of caribou. The Alaska Caribou Steering Committee concluded the most effective mitigation is

S. Schmitz, DO&G

Caribou feeding under an elevated pipeline.

achieved when pipelines and roads are separated by at least 500 ft. Lessees are encouraged in planning and design activities to consider the recommendations for oil field design and operations contained in the final report of the Alaska Caribou Steering Committee, and the mitigation measures and lease advisories in Chapter Nine (Cronin et al. 1994).

b. Buried Pipelines for Oil Transport

Buried pipelines are feasible in the Arctic provided that the integrity of the frozen soils is maintained. Such pipeline configurations have been used in the Milne Point area. There are some important considerations regarding long sections of buried pipe. First is cost, which depends on length, topography, soils, and distance from the gravel mine site to the pipeline. Second, buried pipe is more difficult to monitor and maintain than elevated pipelines. However, significant technological advances in leak detection systems have been made which increase the ease with which buried pipelines can be monitored. These systems are described under the oil spill prevention subsection in this chapter. Third, buried pipelines may involve increased loss of wetlands because of gravel fill. Finally, buried pipelines are sometimes not feasible from an engineering standpoint because of the thermal stability of fill and underlying substrate (Cronin et al. 1994).

3. Natural Gas Transportation

There are various options for transporting natural gas to market. These include pipeline systems, LNG, CNG, gas to solids (GTS), such as hydrates, gas to power, such as electricity, and gas to liquids (GTL) (Mokhatab et al. 2006).

a. Pipelines for Natural Gas Transport

The transportation of natural gas from producing regions to markets requires a transportation system. The gas may have to travel a great distance to reach its point of use. Transportation of natural gas is dependent upon demand and access to storage. Pipelines may follow elevated or buried routes, depending upon the engineering requirements needed and the soils found in the field.

There are three types of pipelines used: gathering system; intrastate and interstate pipelines; and distribution system. Natural gas may require treatment to remove impurities and to prepare it for transport. Treatment may include depressurization and dehydration. To keep the gas flowing along the pipeline route, the gas may also undergo pressurization by compressors, and liquid separation treatment.

During transport the gas is monitored. Pigging facilities and metering stations are constructed along the pipeline to monitor and manage the gas. Central control stations manage information along the pipeline to allow for quick prevention and necessary reaction to problems (Natural Gas Supply Association 2009).

Currently the Alyeska Pipeline company operates a natural gas fuel line from the North Slope fields to the fuel pump stations north of the Brooks Range (Pump Stations 1, 2, 3, and 4). This generally runs parallel to the mainline crude oil pipeline. The purpose of the natural gas is to fuel the pump stations for the Trans-Alaska pipeline (APSC 2009).

b. Liquid Natural Gas (LNG)

There is also the potential for natural gas to be transported as LNG. The likelihood of LNG mode of transport will depend upon the remoteness and the costs and benefits of a particular project. If transport of liquid natural gas is a possibility, it may incorporate use of tankers and marine terminals.

Natural gas that is cooled liquefies. It is stored in refrigerated tanks after processing. Specially built refrigerated tankers transport the LNG to storage locations or to market. The LNG must be

processed to return it to the gas phase. Economies of scale are important to keep the cost per unit to commercially affordable rates (Mokhatab et al. 2006).

4. Natural Gas Storage

The availability of subsurface storage horizons and gas storage facilities affect the technologies and preferred routes of transportation used for natural gas distribution. Under AS 38.05.180(u) the Commissioner of ADNR may authorize subsurface storage of oil or gas to avoid waste or to promote conservation of natural resources. Subsurface storage may be utilized by oil and natural gas developers if favorable geological and engineering properties of the storage reservoir are verified. Subsurface storage must comply with all applicable local, state, and federal statutes and regulations. Refer to Section B(4) above for more information relating to subsurface natural gas storage.

Facilities for gas storage may also serve as integral components of the natural gas transportation system. Cryogenic tanks are used to store LNG (Mokhatab et al. 2006). Gas condensate is stored between production and shipping in condensate storage tanks (Mokhatab et al. 2006). Distances to market and the need to allocate supply at prescribed times of demand may justify the construction and operation of storage facilities along the distribution system route.

5. Tankers and Marine Terminals

In the ice-free ports of Southcentral Alaska, tankers are currently used to transport oil to and from Cook Inlet and from the Alyeska Terminal in Valdez, the terminus of TAPS. The US Coast Guard maintains a vessel traffic service in the Gulf of Alaska and Prince William Sound. Vessels are escorted through Prince William Sound. Two tug boats escort tankers from the Valdez terminal to Cape Hinchinbrook (Alyeska Pipeline Service Company 2009). Use of tankers reduces the risk of a large oil spill, such as the 1989 Exxon Valdez spill in Prince William Sound.

Liquid natural gas may also utilize tankers, if the project analysis deems it to be feasible and cost effective. There are no marine terminals on the north coast of Alaska at the present time due to shallow depths and the lack of ice-free ports.

6. Rehabilitation and Restoration Activities

The lifecycle of an oil field includes another phase of activities for when production ceases and facilities are not active. After an oil field is abandoned, rehabilitation of the affected leased area may be required to restore areas impacted by oil and gas activities. This phase is often described as dismantlement, removal, and restoration (DR&R). The actual activities needed will be a function of the current configuration, and any future planned uses of the site.

Site appearance and function drive the efforts of this phase of the oil field. Revegetation includes reestablishing of a plant cover, and restoration implies returning a disturbed site to ecological conditions similar to those prior to oil and gas development (Linkins et al. 1984). Recovery of wetlands disturbed by gravel infilling may vary, depending on soil moisture content and amount of available soil organic matter (Kidd et al. 1997, citing to Jorgenson and Joyce, 1994). Removal of gravel from pads and roads may be the initial step in rehabilitation. At some sites on the North Slope where gravel fill has been removed, problems have emerged associated with ponding, thaw subsidence, and nutrient cycling. One method preferred by the state is to remove all gravel and create pond habitats that resemble pre-construction conditions. In some cases, full gravel removal may not be the optimum recovery option. In most cases, plant cultivation is desirable with the use of plant species identified as important for water bird habitat. The expected result will influence the techniques used on a case-by-case basis (Linkins et al. 1984). Several plant cultivation treatments have been used on the North Slope, including fertilizer only, native-grass cultivation, Arctophila transplantation, and sedge-plug transplantation. Optimum recovery of the tundra marsh would

include reestablishing vegetation, soil microbiotia, phytoplankton, aquatic invertebrate, and wildlife communities at the impacted site (Kidd et al. 1997).

The rehabilitation of oil and gas sites must be accomplished to the satisfaction of the director of the DO&G, in consultation with the DMLW, ADF&G, ADEC, NSB and any non-state surface owner. The state is currently developing guidelines for site rehabilitation and DR&R, that will assist lessees in planning for site closures.

7. Mitigation Measures and Other Regulatory Protections

Any product ultimately produced from the lease sale area will have to be transported to market; however, it is important to note that the decision to lease oil and gas resources does not authorize the transportation of any product. If and when oil or gas is found in commercial quantities and production is proposed, final decisions on transportation will be made through the local, state, and federal application and permitting processes. Those processes will consider any required changes in oil spill contingency planning and other environmental safeguards, and will involve public participation. The state has broad authority to withhold, restrict, and condition its approval of transportation facilities. In addition, boroughs, municipalities, and the federal government have jurisdiction over various aspects of any transportation alternative (see Chapter Seven). Measures are included in this best interest finding to mitigate potential negative effects of transporting oil and gas (see Chapter Nine). Additional site-specific and project-specific mitigation measures may be imposed as necessary.

F. Oil Spill Risk, Prevention and Response

1. Oil Spill History and Risk

The risk of a spill exists any time crude oil or petroleum products are handled. Oil spills associated with the exploration, development, production, storage, and transportation of crude oil may occur from well blowouts or pipeline or tanker accidents. Petroleum activities may also generate chronic low volume spills involving fuels and other petroleum products associated with normal operation of drilling rigs, vessels, and other facilities for gathering, processing, loading, and storing of crude oil. Spills may also be associated with the transportation of refined products to provide fuel for generators, marine vessels, and other vehicles used in exploration and development activities. A worst case oil discharge from an exploration facility, production facility, pipeline, or storage facility is restricted by the maximum tank or vessel storage capacity, or by a well's ability to produce oil. Companies do not store large volumes of crude at their facilities on the North Slope; rather, produced oil is processed and transported as quickly as possible. This reduces the possible size of a potential spill on the North Slope.

The oil and gas industry has been actively exploring and producing North Slope resources for more than three decades. The 2003 National Research Council report Cumulative Environmental Effects of Oil and Gas Activities on Alaska's North Slope, completed before the corrosion-caused spills in 2006, discussed in Section F(1)(b) below, concluded that, while small spills have occurred in the fields, the spills have not been large or frequent enough to have accumulated effects (NRC 2003).

The ADEC has reported that the primary causes of spills are line failure, equipment failure, human error, containment overflow and tank failure (ADEC 2009d). There were no large spills reported within the lease sale area. However, large spills of crude oil, produced water, seawater, halon and drilling muds have occurred on the North Slope (Table 6.3). Spill records from ADEC show that there have been 24 large spills reported in northern Alaska from October, 2007 to November, 2009, with three spills involving crude oil, 10 spills involving process or produced water, and the remaining involving drilling mud or other substance (Table 6.3). Two large spills of drilling mud

occurred nearby to the north at Gubik well 3 in 2008 (Table 6.3). A large spill is generally considered to be greater than 1,000 gal or lbs.

Large volume oil pipeline releases occurred on May 25, 2010 and January 8, 2011. The May 2010 release was at the Trans-Alaska Pipeline System (TAPS) Pump Station 9, about eight miles south of Delta, Alaska. About 208,950 gal of oil were released to secondary containment. The release was caused by a loss of power during a scheduled maintenance shutdown. Valves allowed the flow of oil into Tank 190, with oil overflow into a lined secondary containment area. About 56,000 gal of oil have been recovered, and spill clean-up is continuing (ADEC 2010a).

Another large volume pipeline release of oil occurred on January 8, 2011 at the TAPS Pump Station 1, located on the North Slope. An estimated 11,130 gal of oil has been recovered, and the cause of the release appears to be from part of the booster pumps' discharge piping in the building. Oil seeped into the booster pump building, but no oil was observed outside the building. This incident cleanup was finalized by the ADEC on January 20, 2011 (ADEC 2011).

Table 6.3. Large spills in the Prudhoe Bay Kuparuk area on the North Slope, October 2007 through December 2009.

Spill Date	Spill Name	Location	Product	Total Released
10/15/2007	Prudhoe Bay, Drill Site 16	Prudhoe Bay/Kuparuk	Produced Water	1,260 gal
10/15/2007	Prudhoe Bay, Drill Site 16	Prudhoe Bay/Kuparuk	Produced Water	1,260 gal
12/16/2007	Kuparuk Drill Site 2U	Prudhoe Bay/Kuparuk	Crude	4,284 gal
12/29/2007	Prudhoe Bay, Well Pad W	Prudhoe Bay/Kuparuk	Drilling Muds	1,470 gal
1/30/2008	Kuparuk Gubik #3	Prudhoe Bay/Kuparuk	Drilling Muds	2,226 gal
2/10/2008	Prudhoe Bay, Drill Site 13	Prudhoe Bay/Kuparuk	Produced Water	1,260 gal
2/30/2008	Oooguruk Development Project	Prudhoe Bay/Kuparuk	Drilling Muds	2,100 gal
3/17/2008	West North Slope Rendezvous 2	Prudhoe Bay/Kuparuk	Crude	2,100 gal
3/26/2008	Kuparuk Gubik #3	Prudhoe Bay/Kuparuk	Drilling Muds	10,920 gal
6/4/2008	Pump Station 1	Prudhoe Bay/Kuparuk	Halon	1,800 lbs
7/15/2008	Anadarko DS-2P Drill Mud Spill	Kuparuk	Drilling Muds	1,000 lbs
8/6/2008	D Pad Well 22 Diesel Release	Prudhoe Bay	Diesel	2,310 gal
9/7/2008	DS-18, Well Brine Spill	Prudhoe Bay	Process Water	5,544 gal
11/3/2008	DS-11, Wells 7, 8, & 38 Seawater Release	Prudhoe Bay/Kuparuk	Seawater	61,626 gal
12/4/2008	Oooguruk 6720 Drilling Mud Release	North Slope	Drilling Muds	6,720 gal
12/25/2008	Kuparuk DS 1L Well 22	Kuparuk	Produced Water	94,920 gal
1/2/2009	Pump Station 4	Pump Station 4	Halon	3,400 lbs
1/12/2009	Milne Point CFP Produced	Milne Point	Produced Water	24,444 gal
2/3/2009	Effluent Water Injection Leak	Kuparuk	Process Water	6,900 gal
2/18/2009	FS-2 Flow line 9A Crude/Gas Release	Prudhoe Bay	Natural gas, crude, produced water	1,890 gal
3/22/2009	DS-1L, Well 16 Produced Water Release	Kuparuk	Produced Water	9,450 gal
5/15/2009	Mud Cutting Containment Cell	North Slope	Drilling Muds	1,008 gal
6/23/2009	Pioneer Ice Damage to Dry Drill Products	Prudhoe Bay	Other	1,200 lbs
11/29/2009	Lisburne Common Line Release - Near DS L03	Prudhoe Bay	Produced Water	45,828 gal

Source: ADEC 2009a, b, c, d.

a. Exploration and Production

Spills related to petroleum exploration and production must be distinguished from those related to transportation because the phases have different risk factors and spill histories. Exploration and production facilities in the lease sale area may include onshore gravel pads; drill rigs; pipelines; and facilities for gathering, processing, storing, and moving oil and gas. These facilities are discussed below. When spills occur at these facilities, they are usually related to everyday operations, such as fuel transfers. Large spills are rare at the exploration and production stages because spill sizes are limited by production rates and by the amount of crude oil stored at the exploration or production facility. A well can only spill as much oil as it can produce without assistance. Some wells cannot produce without mechanical assistance, and if an accident occurs, oil ceases to flow.

A spill of produced water, natural gas and crude occurred on December 29, 2009 in the 18-inch three-phase common carrier pipeline at a location about 1.5 miles from the Lisburne Production Center (LPC). The pipeline ruptured along the bottom, creating an opening of two ft in length, and released about 1,091 bbl of crude oil, produced water, and natural gas. The cleanup goals were achieved by response crew efforts that ended in January, 2010 (ADEC 2009b).

The most dramatic form of spill can occur during a well blowout, which can take place when high pressure gas is encountered in the well and sufficient precautions, such as increasing the weight of the drilling mud, are not effective. The result is that oil, gas, or mud is suddenly and violently expelled from the well bore, followed by uncontrolled flow from the well. Blowout preventers (BOP), which immediately close off the open well to prevent or minimize any discharges, are required for all drilling and work-over rigs and are routinely inspected by the AOGCC to prevent such occurrences.

Blowouts are extremely rare in Alaska and their numbers decline as technology, experience, and regulation impact drilling practices. A blowout that results in an oil spill has never occurred in Alaska, however natural gas blowouts have occurred. A gas blowout occurred at the Cirque No. 1 well in 1992. The accident occurred while ARCO workers were drilling an exploratory well and hit a shallow zone of natural gas. Drilling mud spewed from the well and natural gas escaped. It took 2 weeks to plug the well (Anchorage Times 1992). In 1994, a gas kick occurred at the Endicott field I-53 well. BP Exploration was forced to evacuate personnel and shut down most wells on the main production island. No oil was released to the surface, as the well had not yet reached an oil-bearing zone. There were no injuries, and the well was controlled and plugged 3 days later by pumping heavily weighted drilling muds into it (ADN 1994; Scagliotti 1994; AOGCC 2009).

On April 20-22, 2010, a blowout incident occurred in the Gulf of Mexico involving a semi-submersible rig, the Deepwater Horizon (Transocean 2010b; Transocean 2010d; Transocean 2010d). At the time of the incident, 126 crew members were onboard; 115 were evacuated and 11 died (Transocean 2010b; Transocean 2010d). Before the rig sank, the response team was not able to stop the flow of oil and gas (Transocean 2010d), the blowout preventer failed (BP 2010b), and a large release of hydrocarbons into the water occurred. The well was shut-in on July 15, 2010, a relief well successfully intercepted the annulus of the MC252 well on September 15, 2010, and cement was successfully pumped into the annulus on September 17, 2010 (BP 2010a). Although this incident did not occur in Alaskan waters, the State of Alaska is closely monitoring information available from the Deepwater Horizon incident, and may modify or issue new mitigation measures or lessees advisories as needed as more information becomes available.

b. Pipelines

Both state and federal agencies have oversight of pipelines in Alaska. State agencies include the Petroleum Systems Integrity Office (PSIO) and DO&G within DNR; the State Pipeline Coordinator's Office (SPCO), the federal and state Joint Pipeline Office (JPO); and ADEC. Federal

agencies include PHMSA within the U.S. Department of Transportation; and the Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE), formerly the U.S. Minerals Management Service (MMS).

The pipeline system that transports North Slope crude includes flow lines, gathering lines, and pipelines that carry the crude to processing facilities and to Pump Station 1, where the oil enters TAPS for transport to the port of Valdez. Pipelines vary in size, length, and amount of oil contained. A 14-inch pipeline can store about 1,000 bbl per mile of pipeline length. Under static conditions, if oil were lost from a 5-mile stretch of this pipeline (a hypothetical distance between emergency block valves), a maximum of 5,000 bbl of oil could be discharged if the entire volume of oil in the segment drained from the pipeline.

Oil spills in 2006 and 2009 have made the oil and gas industry, local, state, and federal regulators, and the public aware of potentially widespread pipeline corrosion issues on the North Slope. On March 2, 2006, 6,357 bbl (267,000 gal) from a transit line in Prudhoe Bay spilled over approximately 2 acres of tundra – the largest spill in Prudhoe Bay history (Loy 2006; ADEC 2009a, b). The cause of the leak was internal microbiological corrosion the pipeline (Bailey 2006). BP Exploration Alaska, the Prudhoe Bay operator, had not pigged the pipeline to test for internal corrosion since 1998 (Loy 2006). A one-quarter inch hole formed in the bottom of the pipeline in a section that had been buried under a caribou crossing. The snow covered the leak, delaying detection; ultimately, the odor exposed the leak to a worker. A report prepared by a team of BP and state investigators in April 2006 stated that spill alarms went off for at least 5 consecutive days in late February; however, the alarms were dismissed by operators monitoring the system as false. Crews recovered over 1,428 bbl (60,000 gal) of the spilled oil, and, after the $6 million cleanup was completed, ADEC estimated the tundra suffered minimal environmental damage.

On March 9, 2006, spill responders found 12 bbl (500 gal) of crude oil and produced water that had leaked from a gathering line in the Kuparuk unit and another 4.8 bbl (200 gal) were collected in a catch basin (Loy 2006). The cause of the leak was also determined to be holes caused by internal corrosion.

On August 6, 2006, BP announced that it needed to shut down the Prudhoe Bay field in order to address pipeline corrosion issues (Nelson 2006). A corrosion test detected a small leak in a transit line and the entire eastern operating area was completely shut in. In response to the August 2006 shutdown, transit lines were pigged weekly and a continuous corrosion inhibitor was added to the transit lines.

Undertaking a multi-year, $500 million project, BP replaced the 16-mile transit pipeline system in the Prudhoe Bay area (except for Lisburne), completing it in December, 2008 (Quinn 2009).

On December 19, 2006, 234,738 gal of produced water and 150 bbl (6,300 gal) of crude oil were spilled at Gathering Center 2 (ADEC 2010c). The loss was attributed to tank corrosion caused by mechanical failure. Misalignment of an agitation jet caused a hole to erode through the bottom of the tank. One to 2 gal of produced water flowed through a hole in the containment liner to the gravel pad. All of the oil was recovered.

Other spills occurred in 2009. On November 29, 2009, a rupture in an 18-inch pipeline released 45,828 gal of produced water. On December 21, 2009, a pipeline leak at a wellhead at Drill Site 6, Well 11 sprayed up to 700 gal of water and about 100 gal of crude on the well pad and surrounding tundra (ADEC 2009a, b). These spills have heightened the concern about risks relating to aging infrastructure on the North Slope.

Two large volume oil pipeline releases occurred on May 25, 2010 and January 8, 2011. These are discussed in more detail above in Section F(1).

After the 2006 spills and subsequent spill releases, the state made it a priority to address issues of corrosion and pipeline monitoring. Increased state and national awareness resulted in a number of changes in the public and private sectors. First, operators assert they are now monitoring corrosion more closely, including pigging transit and common carrier lines on a regular basis, and updating and strictly enforcing best industry standards for routine maintenance practices. The state has also examined pipeline corrosion issues closely and has expanded efforts to monitor and regulate both gathering and common carrier lines. ADEC promulgated new regulations regarding education, preparation for spills, and spill response; these regulations went into effect in December 2006. Updated regulations were issued on October 9, 2008 (18 AAC 75).

On December 29, 2006, the "Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006" (PIPES Act H.R. 5782) was signed into federal law. Under the PIPES Act, hazardous liquid pipeline operators are required to develop integrity management programs for transmission pipelines.

c. Tankers

Shallow nearshore waters and lack of ice free ports prevent the use of tankers for transporting oil from the North Slope. Alaska's most catastrophic oil spill was the March 1989 *Exxon Valdez* tanker spill in Prince William Sound, the second largest recorded in U.S. waters. It spilled nearly 10.8 million gal of crude oil; contaminated fishing gear, fish, and shellfish; killed numerous marine birds and mammals; and led to the closure or disruption of many Prince William Sound, Cook Inlet, Kodiak, and Chignik fisheries (Graham 2003; Science Daily 2003; City of Valdez 2010; Alaska Office of the Governor 1989). Effects of oil spills on fish and other wildlife are discussed in Chapter Eight.

Other large tanker spills include the 1987 tanker Glacier Bay spill of 2,350-3,800 bbl of North Slope crude oil being transported into Cook Inlet for processing at the Nikiski Refinery (ADEC 1988). Less than 10% of the oil was recovered, and the spill interrupted commercial fishing activities in the vicinity of Kalgin Island during the peak of the sockeye salmon run.

Both incidents demonstrated that preventing catastrophic tanker spills is easier than cleaning them up, and focused public, agency, and legislative attention on the prevention and cleanup of oil spills. Numerous changes were effected on both the federal and state levels. At the state level, new statutes created the oil and hazardous substance spill response fund (AS 46.08.010), established the Spill Preparedness and Response (SPAR) Division of ADEC, (AS 46.08.100), and increased financial responsibility requirements for tankers or barges carrying crude oil up to a maximum of $100 million (AS 46.04.040(c)(1)). Regulations and laws regarding oil spills are discussed in Chapter Seven.

d. Alaska Risk Assessment of Oil and Gas Infrastructure

In May 2007, the Alaska Risk Assessment (ARA) project was launched by the ADEC. The purpose of the 3-year, $5 million initiative is to evaluate Alaska's oil and gas infrastructure for its ability to operate safely. Based upon Phase I of the investigation, the project scope was revised, and the investigation changed focus to North Slope pipeline spills that resulted in loss of integrity. A North Slope Spills Analysis (NSSA) for specific North Slope pipelines was issued in November 2010, and compiled and analyzed causal information associated with the North Slope pipeline spills. The spill analysis investigated risks to oil infrastructure using available spill data, information about causal factors, and included seven specific recommendations for reducing spills from Alaska infrastructure (ADEC 2010b).

A complementary report was issued, the Alaska Risk Assessment of Oil and Gas Infrastructure Oversight Report, that provided recommendations for future oversight activities for oil transportation (Cycla Corporation 2010). The report provided an overview of risk management and oversight systems used by other jurisdictions, and provided recommendations designed to enhance risk management practices of the ADEC and to strengthen risk management practice across Alaska

oversight agencies (Cycla Corporation 2010). Key findings from this report are that the primary job of regulators is to require practices that reinforce the operators' responsibility to ensure safe operation of their facilities; the State should not undertake a risk assessment without significant cooperation from the operators; the existing system should be refined rather than implementing radical changes; and operator reporting should be expanded to improve the understanding of the effectiveness of management systems (Cycla Corporation 2010). Specific recommendations were divided into two categories: recommended future Alaska oversight agency risk management activities, and recommended ADEC activities (Cycla Corporation 2010).

e. Gulf of Mexico Incident:

There was an oil release in the offshore region of the Gulf of Mexico in 2010. The Deepwater Horizon was a semi-submersible drilling unit (Transocean 2010a) operating on Mississippi Canyon Block 252 (MC252) (BP 2010a) in federal Outer Continental Shelf (OCS) waters located in the United States Gulf of Mexico, about 41 miles offshore of Louisiana (Transocean 2010c; Transocean 2010b; Transocean 2010d). BP Exploration & Production, Inc. was the lease operator (Transocean 2010d).

According to official reports, on April 20, 2010, approximately 10:00 p.m. Central Time, a fire and explosion were reported on the Deepwater Horizon (Transocean 2010b; Transocean 2010d). The oil drilling rig sank on April 22, 2010 (Transocean 2010d).

Several attempts to stop the flow of oil and gas, and to make the blow out preventer operational were attempted. The well was shut-in on July 15, 2010, a relief well was drilled, and the well was pumped with cement on September 17, 2010 (BP 2010a).

The U.S. Bureau of Ocean Energy Management, Regulation and Enforcement and the U.S. Coast Guard have joint jurisdiction over the incident, and are investigating the factors that caused the event (USCG and MMS 2010). The final report is scheduled to be issued in July 2011 (USCG and BOEMRE 2011).

The National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling (also called the Oil Spill Commission, or OSC) was established by presidential executive order in May 2010. Its objectives are to examine the relevant facts and circumstances concerning the root causes of the Deepwater Horizon explosion, fire, and oil spill and to develop options to guard against, and provide recommendations to mitigate the impact of, any oil spills associated with offshore drilling in the future (DOE 2010). The OSC report issued on January 11, 2011 concluded that several errors were made and that systematic failures in risk management are potential problems that may impact the oil and gas industry (OSC 2011).

The OSC report presents 31 specific recommendations for seven categories: improving the safety of offshore operations; safeguarding the environment; strengthening oil spill response, planning, and capacity; advancing well-containment capabilities; overcoming impacts of the Deepwater Horizon spill and restoring the Gulf of Mexico; ensuring financial responsibility; and promoting congressional engagement to ensure responsible offshore drilling (OSC 2011).

2. Oil Spill Prevention

A number of measures contribute to the prevention of oil and natural gas related spills during the exploration, development, production, and transportation of crude oil and natural gas. Some of these prevention measures are presented as mitigation measures in Chapter Nine, and some are discussed in this chapter. Prevention measures are also described in the oil discharge prevention and contingency plans that the industry must prepare before beginning operations. Thorough training, well-maintained equipment, and routine surveillance are important components of oil spill

prevention. From 1949-2008, there were 18 blowouts in Alaska: 15 of those occurred before the 1990s, two occurred during the 1990s, and one occurred in 2008; all except one were gas blowouts (AOGCC 2009). Improvements in well control have come about because of better equipment and controls, redundancy in critical components, training, and frequent testing (AOGCC 2009).

Technical design of pipelines and other facilities also reduces the chance of oil spills. National industry standards and federal, state, and local codes and standards, help assure the safe design, construction, operation, maintenance, and repair of pipelines and other facilities. A quality assurance program promotes: adequate inspection of the pipelines to identify any safety or integrity concerns; regular maintenance, including installing improved cathodic protection, and using corrosion inhibitors; and continuing regular visual inspections to ensure safe and reliable operation.

If and when oil or gas is found in commercial quantities and production is proposed, final decisions on transportation will be made through the local, state, and federal application and permitting processes. Those processes will consider any required changes in oil spill contingency planning and other environmental safeguards, and will involve public participation.

The oil and gas industry employs, and is required to employ, many techniques and operating procedures to help reduce the possibility of spilling oil, including:

- Use of existing facilities and roads;
- Water body protection, including proper location of onshore oil storage and fuel transfer areas;
- Use of proper fuel transfer procedures;
- Use of secondary containment, such as impermeable liners and dikes;
- Proper management of oils, waste oils, and other hazardous materials to prevent ingestion by bears and other wildlife;
- Consolidation of facilities;
- Placement of facilities away from fishbearing streams and critical habitats;
- Siting pipelines to facilitate spilled oil containment and cleanup; and,
- Installation of pipeline leak detection and shutoff devices.

a. Blowout Prevention

A blowout is the uncontrolled gushing of fluids from a formation that the hole has penetrated. Prevention of blowouts is a priority. In addition, operators must have plans for preventing and anticipating blowouts. Operators must train employees how to react safely in the case of a blowout (Van Dyke 1997).

Each well has a blowout prevention program that is developed before the well is drilled. Operators review bottom-hole pressure data from existing wells in the area and seismic data to learn what pressures might be expected in the well to be drilled. Engineers use this information to design a drilling mud program with sufficient hydrostatic head to overbalance the formation pressures from surface to the total depth of the well. They also design the casing strings to prevent various formation conditions from affecting well control performance. Blowout preventer (BOP) equipment is installed on the wellhead after the surface casing is set and before actual drilling begins. BOP stacks are routinely tested in accordance with government requirements. AOGCC regulates compliance with blowout prevention requirements (AOGCC 2010a).

Wells are drilled according to the detailed plan. Drilling mud and well pressures are continuously monitored, and the mud is adjusted to meet the actual wellbore pressures. The weight of the mud is the primary well control system. If a kick (sudden increase in well pressure) occurs, the well is shut-in using the BOP equipment. This prevents further entry of formation fluids into the well borehole. The BOP closes off and contains fluids and pressures in the annulus and in the drill pipe. Technicians take pressure readings and adjust the weight and density of the drilling mud to compensate for the increased pressure (Van Dyke 1997).

J. Easton, DO&G

Example of a blowout preventer (BOP) at Jacob's Ladder exploration well, North Slope.

Drilling of a relief well can address an over-pressured well. If a blowout occurs, another drilling rig is moved to the location, and a well borehole is drilled to intercept or pass within a few feet of the bottom of the "wild" well. The "wild" well is killed by circulating high density fluid down the relief well and up into the "wild" well (Van Dyke 1997). Conditions may require the construction of an ice or gravel pad and road for the relief well. The operator will look for the closest appropriate drill rig. If the rig is in use, industry practice dictates that, when requested, the operator will release the rig for emergency use. This can take weeks to implement.

b. Leak Detection

Leak detection systems and effective emergency shut-down equipment and procedures are essential in preventing discharges of oil from any pipeline that might be constructed in the lease sale area. Once a leak is detected, valves at both ends of the pipeline, as well as intermediate block valves, can be manually or remotely closed to limit the amount of discharge. The number and spacing of the block valves along the pipeline will depend on the size of the pipeline and the expected throughput rate (Nessim and Jordan 1986). Industry on the North Slope has used the volume balancing method, which involves comparing input volume to output volume.

The technology for monitoring pipelines is continually improving. Leak detection methods may be categorized as hardware-based (optical fibers or acoustic, chemical, or electric sensors) or software-based (to detect discrepancies in flow rate, mass, and pressure) (Scott and Barrufet 2003). Leak detection methods include acoustic monitoring, pressure point analysis, ultrasound, radiographic testing, magnetic flux leakage, the use of coupons, regular ground and aerial inspections, and combinations of some or all of the different methods. The approximate location of a leak can be determined from the sensors along the pipeline. A computer network is used to monitor the sensors and signal any abnormal responses. In recent years, computer-based leak detection through a Real-Time Transient Model has come into use, to mathematically model the fluid flow within a pipe (Scott and Barrufet 2003). Modern pipeline systems are operated from control centers with

computer connectivity with satellite and telecommunication links to strive for rapid response and constant monitoring of pipeline conditions (PHMSA 2010b).

Pressure Point Analysis (PPA) measures changes in the pressure and velocity of the fluid flowing in a pipeline to detect and locate leaks. PPA has successfully detected holes as small as 1/8-inch in diameter within a few seconds to a few minutes following a rupture (Farmer 1989). Automated leak detection systems such as PPA operate 24 hours per day and can be installed at remote sites. Information from the sensors can be transmitted by radio, microwave, or over a hardwire system.

Three systems can be employed that detect leaks down to 0.12% of rated capacity (100 bbl per hour). These include line volume balance, deviation alarms, and transient volume balance.

Line volume balance (LVB) checks the oil volume in the pipeline every 30 minutes. The system compares the volume entering the line with the volume leaving the line, adjusting for temperature, pressure, pump station tank-level changes, and slackline conditions.

There are three types of deviation alarms: pressure, flow, and flow rate balance. Pressure alarms are triggered if the pressure at the suction or discharge of any pump station deviates beyond a certain amount. Flow alarms are triggered if the amount of oil entering a pump station varies too much from one check time to the next. Flow rate balance alarms are triggered if the amount of oil leaving one pump station varies too much from the amount entering the next pump station downstream. This calculation is performed on each pipeline section about six times a minute.

Transient volume balance (TVB) can detect whether a leak may be occurring and identify the probable leak location by segment, especially with larger leaks. While the LVB leak detection system monitors the entire pipeline, the TVB system individually monitors each segment between pump stations. Because the TVB indicates in which area a leak may be occurring, focused reconnaissance, and earlier response mobilization are possible (APSC 2009).

There are several other leak detection systems. Leck Erkennung und Ortangs System (LEOS) is a leak detection and location system manufactured by Siemens AG. The system has been in use for 21 years and in over 30 applications. LEOS consists of a three-layer gas-sensor tube that is laid next to the pipeline. The inner layer is a perforated gas transport tube of modified PVC (polyvinyl chloride). A diffusion layer of EVA (ethylene vinyl acetate) surrounds and allows gasses to enter the inner tube. A protective layer of braided plastic strips forms the outer layer. The tube is filled with fresh air, and the air is evacuated through a leak detector at regular intervals. If a leak occurs, hydrocarbon gases associated with the leak enter the tube and are carried to the gas detector. The system is totally computer controlled, self-checking, and re-setting. Background gases are calibrated at setup and checked regularly. The system will pick up previous contamination and organic decomposition. The location of the leak is determined by monitoring the time that leaked gas arrives at the detection device. The sensor allows determination of the size and location of the leak (NRC 2003). The system is very low maintenance and will last the life of the pipeline. Special protective adaptations are made if the system will operate in cold temperatures and for the backfill installation method used to install the pipeline. The tube is placed in a protective cover, and the system is tested continuously as the segments are installed. LEOS is strapped to the oil pipeline next to the poly spacers that separate the gas line from the oil line. The system detects leaks from both lines, and operators are able to tell the difference between the two. Engineers estimate that it takes about 5 to 6 hours for leaked molecules to migrate to the LEOS tube. The air inside the tube is evacuated and tested every 24 hours (Scott and Barrufet 2003).

Design and use of “smart pigs,” data collection devices that are run through the pipeline while it is in operation, have greatly enhanced the ability of a pipeline operator to detect internal and external corrosion and differential pipe settlement in pipelines. Pigs can be sent through the pipeline on a regular schedule to detect changes over time and give advance warning of any potential problems.

The Trans-Alaska Pipeline System operation has pioneered this effort for Arctic pipelines. The technique is now available for use worldwide and represents a major tool for use in preventing pipeline failures. Although some older pipelines cannot facilitate smart pigs, the PIPES Act of 2006 requires the development of integrity management programs for pipelines in high consequence areas. Basic requirements for an Integrity Management Plan include periodic integrity assessment of pipelines that could affect high consequence areas (HCAs). Integrity assessments are performed by in-line inspection (also referred to as "smart pigging"), hydrostatic pressure testing, or direct assessment. Through these assessment methods, potentially injurious pipeline defects that could eventually weaken the pipe, or even cause it to fail, are identified early and can be repaired, thus improving the pipe's integrity.

The Forward Looking InfraRed (FLIR) pipeline monitoring program assists in detecting pipeline leaks and corrosion in the Kuparuk oil field. Originally developed by the military (NRC 2003), FLIR uses infrared sensors to sense heat differentials. A leak shows up as a "hot spot" in an FLIR video, in both daytime and night time images (MMS 2008). In addition, water-soaked insulation surrounding a pipeline is visible because of the heat transfer from the hot oil to the water in the insulation and finally to the exterior surface of the pipeline. FLIR is also effective in discovering water-soaked insulation areas that have produced corrosion on the exterior wall of the pipeline (St Pierre 1999).

FLIR also has applications in spill response. Infrared photography can be used to quickly and accurately determine the area of the spill, distinguishing between oil and substances that might look like oil to human eyes (NRC 2003). This allows swift and accurate reporting of the spill parameters to the appropriate agencies. The incident command team is able to receive information near real-time, and can therefore make timely decisions.

ARCO studied the use of vertical loops at Alpine in lieu of block valves and concluded that, in conjunction with emergency pressure let down valves or direct valves, vertical loops are better than manual block valves for reducing catastrophic failures. A vertical loop is an artificial high point in a pipeline. If a pipe leaks, the vertical loop becomes the high point and the oil cascades from one vertical loop to the next, creating a vapor space and isolating the fluid on the uphill side from the leak (Cederquist 2000). BLM reported that vertical loops greatly reduce the environmental effects on tundra, provide for a safer line, and lessen the probability of spillage due to river induced pipeline damage. It also acknowledged that the placement of a pipeline at depth beneath a river could make detection and cleanup of a spill in the buried segment difficult (BLM 2008b).

The Pipeline and Hazardous Materials Safety Administration has jurisdiction over cross-country pipelines. The federal 49 CFR 192, Subpart O addresses the gas transmission pipeline integrity management regulations and requirements. Identification of High Consequence Areas (HCA) and the required integrity management program are components of what a gas transportation system operator must do to remain in compliance and to provide adequate planning, implementation and system maintenance. The technologies used for future gas transportation projects will determine the actual integrity management program components that must be implemented (PHMSA 2010a).

G. Oil Spill Response

By law, the responsible party (RP) is responsible for preventing and responding to oil spills, including notifying federal, state, and local authorities. ADEC regulations (18 AAC 75.400) require that oil companies prepare Oil Discharge Prevention and Contingency Plans (C-plans). C-plans must set forth measures designed to prevent spills and must demonstrate sufficient resources are available to contain or control and clean up that occur. A key component of a plan is ready access to trained personnel and equipment. Spill preparedness and response practices are driven by the state's Unified Plan, the North Slope Subarea Plan, and the practices developed by the North Slope's oil spill

response cooperative. The North Slope Subarea Plan primarily serves the area within the North Slope Borough (ADEC 1999; ADEC 2007a).

Regardless of the nature or location of a spill, the North Slope Subarea Plan sets these objectives for all response actions:

- Ensure safety of responders and the public.
- Stop the source of the spill.
- Deploy equipment to contain and recover the spilled product.
- Protect sensitive areas (environmental, historic properties, and human use).
- Track the extent of the spill and identify affected areas.
- Clean up contaminated areas and properly dispose of wastes.
- Notify and update the public. Provide avenues for community involvement where appropriate (ADEC 1999; ADEC 2007a).

1. Response Teams

The Alaska Regional Response Team (ARRT) monitors the actions of the RP. The Team is composed of representatives from 15 federal agencies and one representative agency from the state. The ARRT is co-chaired by the U.S. Coast Guard and EPA. ADEC represents the State of Alaska. The team provides coordinated federal and state response policies to guide the Federal On-Scene Coordinator in responding effectively to spill incidents and has developed a Unified Plan. The Statewide Oil and Hazardous Substance Incident Management System Workgroup, which consists of ADEC, industry, spill cooperatives, and federal agencies, published the Alaska Incident Management System (AIMS) for oil and hazardous substance response. The ARRT has developed guidelines regarding wildlife, in-situ burning, the use of dispersants, and the protection of cultural resources, which include archaeological and historic sites (ADEC 1999; ADEC 2007a). Each operator identifies a spill response team (SRT) for their facility, and each facility must have an approved

L. Silfven, ADEC

A Mutual Aid drill near TAPS pump station 3 in which the team is practicing deploying river boom, North Slope foothills area.

C-plan. Company teams provide on-site, immediate response to a spill event. The SRTs are integrated into the North Slope Spill Response Team (NSSRT), comprised of 115 field responders per day (ACS 2010b).

First, responders attempt to stop the flow of oil and may deploy booms to confine oil that has entered the water. The responders may deploy booms to protect major inlets, wash-over channels, and small inlets. Finally, deflection booming would be placed to enclose smaller bays and channels to protect sensitive environmental areas. If the nature of the event exceeds the facility's resources, the RP calls in its response organization. The SRT:

- identifies the threatened area;
- assesses the natural resources, i.e., environmentally sensitive areas such as major fishing areas, spawning or breeding grounds;
- identifies other high-risk areas such as offshore exploration and development sites and tank-vessel operations in the area;
- obtains information on local tides, currents, prevailing winds, and ice conditions; and,
- identifies the type, amount, and location of available equipment, supplies, and personnel.

The next action is containment. It is especially important to prevent oil spills spreading rapidly over a large area. Cleanup activities continue as long as necessary, without any time frame or deadline.

First responders to a natural gas leak would likely be associated with the pipeline operator. Operators on oil and gas leases are the primary persons responsible for planning for, implementing and completing an approved plan of operations, which includes provisions for operations, supplies, equipment, access, facilities and rehabilitation of the affected leased area (ADNR 2009a).

In addition, fire department personnel in nearby villages may be called to respond to fire incidents. Barrow and Nuiqsut have full time fire departments, and Anaktuvuk Pass and Kaktovik have volunteer fire departments. Others trained in fire response could be called to an oil and gas related fire event.

2. Training

Individual members of the SRT train in basic spill response. Alaska Clean Seas (ACS), the North Slope's oil spill cleanup cooperative, offers dozens of classes in topics ranging from Incident Command to Fate and Behavior [of oil], Skimmer In Fast Tanks and Test Tanks, Winter Spill Response, Radio Communications, Tundra Cleanup Techniques, Staging Area Management, Behavior of Oil in Broken Ice, and others. Alaska Clean Seas provides spill response training each week in 2 to 4 hour sessions to each of the North Slope Spill Response Teams (ACS 2010b). ACS has five labor categories (ACS 2008). Entry level General Laborers may have minimal or no experience and perform tasks associated with mobilizing, deploying, and supporting cleanup. Over time, each General Laborer will receive additional training and be brought to at least the next training level, Skilled Technicians. Skilled Technicians receive specific training or experience in spill response; they operate skimmers and other equipment used to retrieve spilled oil. Team Leaders have additional responsibilities and may be charged with managing portions of a response. ACS's two remaining labor categories relate to Vessel Operation (ACS 2010b).

3. Response Organizations

The response organizations for the lease sale area will be determined by the operators of the oil and gas exploration and development activities. There are organizations that currently provide response services for the North Slope area. The response organization for this lease sale area may provide response services that are similar to those described here for ACS.

ACS is an industry-sponsored, not-for-profit organization that provides the oil spill response function in support of petroleum-related activities on the North Slope, in the coastal and OCS waters off the coast of the North Slope of Alaska, and along the Trans-Alaska Pipeline from Pump Station One to Milepost 167 (ACS 2010a). The organization was originally established in Prudhoe Bay in 1979 under the name of ABSORB (Alaskan Beaufort Sea Oilspill Response Body) to support offshore exploration ventures in the Alaskan Beaufort Sea. In 1990, ACS owner companies expanded the mission to include response operations both offshore and onshore. Environmental support includes field environmental audits, storm water run off management, maintenance of water generator status, hazardous waste shipments, wildlife hazing, and reporting. Membership is optional, and member companies pay an initiation fee and annual fee, daily rig fees when engaging in drilling, and annual production fees for facilities in production (ACS 2010b).

Members of the ACS organization include Alyeska Pipeline Service Company, Anadarko Petroleum Corporation, BP Exploration (Alaska), Brooks Range Petroleum Corporation, ConocoPhillips Alaska Inc., Eni US Operating Company Inc., ExxonMobil Production Company, FEX L.P., Pioneer Natural Resources (USA), and Shell Offshore Inc. (ACS 2010a).

Any responses to oil spills in the lease sale area by ACS would be for ACS organization members. Exploration and development companies would need to join the Alaska Clean Seas organization to benefit from its spill response services provided to members.

Local fire departments and organizations with trained first responders may be called to action, depending upon the emergency incident circumstances.

4. ACS Responders and Mutual Aid Agreements

For an oil spill in the lease sale area, oil and gas operators who are members of ACS may call upon ACS for assistance with both spill planning and response. Members may also engage in Mutual Aid Agreements with other ACS members, providing each other with shared resources, both personnel and equipment, in the event of a spill. ACS provides manpower and equipment resources from its main base in Deadhorse and from within each of the operating oilfield units to assist in spill containment and recovery. ACS has 78 full time staff on the North Slope and in Anchorage; about half of ACS' employees and contractors are located on the North Slope and all are available for response operations. Including trained volunteers, ACS has available a minimum of 115 spill response personnel on the North Slope each day (ACS 2010b). ACS personnel are on call 7 days a week, 24 hours a day while they are on-shift. The time necessary to arrive at a spill site with the appropriate equipment depends on the spill situation.

North Slope operating companies coordinate with ACS to ensure a pool of trained personnel is available for an extended response. Over 500 trained employees, contractors, and ACS-trained Village Response Teams are available for response, with a minimum of 115 trained responders immediately available on a daily basis via mutual aid agreements. All on-shift members of the NSSRT are available for call-out. ACS also manages existing contracts with several spill response and service contractors. Contracted response services include labor and equipment, aviation support, telecommunications services, and computerized mapping (ACS 2008).

ACS trains North Slope village teams to support oil spill response capability. Intensive training courses for village team members include winter and summer oil spill operations, hazardous waste operations, oil spill post-emergency response, oil spill assessment, tracking and detection of oil, skimmer operations, incident command, and basic radio voice procedures. The teams take part in field exercises and the annual North Slope mutual aid response exercises. While ACS does not clean up spills in the villages, the village responders may have the training to do so.

5. Initiation of the Incident Management Team

Response actions vary greatly with the nature, location, and size of the spill. Upon direction of the Incident Command, the general response activities may include location and stop of the spill or release and estimation of the spill amount. The substance's chemistry and trajectory are determined, and the equipment needed to confine the spill or to protect sensitive areas is determined. Damage assessment is conducted of the oiled and impacted areas, and a cleanup plan is developed and implemented.

Response equipment might include earth-moving equipment, airplanes, helicopters, boats, boom, skimmers, sorbents, and in-situ burning equipment. The responsible party and its contractors usually perform response activities with assistance and monitoring by federal and state agencies.

ACS has purchased and maintains a spill response equipment inventory valued in excess of $25 million and ACS members have built corresponding inventories capable of meeting the immediate response needs of their respective units, bringing the value of inventory to $50 million. This equipment is designed to respond to spills within the defined area of operations, under all environmental conditions. Members share resources in the event of a significant spill within any of the North Slope operating units. To assist with this task, ACS manages the combined inventory of all dedicated North Slope spill response assets in a single, computerized maintenance and job order system (ACS 2008). Additional equipment and trained personnel are available through ACS' agreements with contractors or master services agreements.

There are emergency operation centers located in Deadhorse, at satellite areas in Alpine, Kuparuk, Milne Point fields and at the Prudhoe Bay Operations Center. With assistance from the ACS base operations center, field assigned ACS technicians support the operating area facilities and sites, while the Deadhorse locations are managed by ACS base personnel. Mobile facilities are also available (ACS 2010b).

ACS established a central Incident Command Post at Deadhorse as a control point for oil spill response radio and telephone systems for the entire North Slope area, extending into the Beaufort

P. Lhotka, ADEC

Spill response team removing contaminated water from the top of ice, Flow Station 2, Prudhoe Bay, 10/18/07.

Sea. This radio and telephone communications system is capable of being rapidly deployed by sea, land, or air to local and remote areas in support of onshore or offshore oil spill response actions. Remote control circuits for 14 permanent Very High Frequency (VHF) repeaters and marine coast stations, installed at strategic locations in the production area and pipeline corridor, are routed via private microwave circuits into the system (ACS 2008). Other High Frequency (HF) and Ultra High Frequency (UHF) radios are also connected to the system. Communication is then possible among all users, whether marine-based radios, company headquarters or supply depots, ICP, hand held portable radios, or aircraft radios. This gives each member company access to all of the radio systems, regardless of the type of radio it is using. ACS also has mobile VHF and UHF radios, base and mobile stations, satellite telephones with data capabilities, and portable repeaters for field use in its oil spill response program (ACS 2008).

Other spill response organizations operate in the state. Alyeska Pipeline's SERVS (Ship Escort Response Vessel System) operates in Prince William Sound. Other operational equipment includes INMARSAT satellite telephone systems, operating independently of wires and separate from the VHF, UHF, and other radio systems, at Deadhorse on the North Slope. The name INMARSAT is derived from "international, marine, satellite." The system can reach anywhere in the world via satellite. An INMARSAT system can be mounted on a boat, in such a way that, regardless of heavy seas or other disturbance, the antenna beam cannot be shaken off the satellite and communication disconnected. Ships, barges, aircraft, oil spill response agencies, ground personnel, and anyone with a telephone can be reached via this system.

6. Spill Response

ACS and the North Slope operators employ a tiered system for responding to spills. Small, non-emergency spills are cleaned up by the operator or ACS personnel. Spills requiring the resources of ACS and the responsible party's SRT are considered Tier I spills. If a spill requires more than the resources of ACS and the RP, it is considered a Tier II spill. Other North Slope operators share their resources, both personnel and equipment. Mutual aid is a system that utilizes SRTs from companies other than that of the responsible party. Such spills usually require some longer-term cleanup.

An extremely large spill or an incident lasting several months may require resources unavailable on the North Slope and is classified as a Tier III spill. ACS may enlist assistance from spill responders from Cook Inlet (CISPRI) and Prince William Sound (SERVS) or from its Auxiliary Contract Response Team (ACRT) subcontractors: CCI, Penco, and Trident (ACS 2010b), as well from across the U.S. and other countries (ACS 2008). Response strategies are set forth in ACS' Technical Manual, providing specific scenarios for environmental and seasonal conditions found on the North Slope.

7. Research and Development

Building on studies addressing Arctic oil spill response, ACS developed a technical manual for spill response on the North Slope and Beaufort Sea (ACS 2008). The three-volume manual was revised in 2008. The manual and the background documents supporting it are a compilation of the latest research and best available technology regarding oil spill response in the Arctic. The response tactics in the manual are designed to be used as building blocks for operators to prepare facility-specific response scenarios in their C-plans. The manual describes key response planning parameters for a variety of climatic and environmental conditions that may be encountered. It is intended to provide direction and consistency in developing generic scenarios for a variety of receiving environments, and eliminate the need for individual plans to repeat technical details. The manual consists of three volumes: Tactics Descriptions, Map Atlas, and North Slope Incident Management System and will augment the C-plans that each operator must prepare before beginning operations. The manual represents a major advance in the organization and coordination of spill

response planning and preparedness on the North Slope. The reader is referred to the Technical Manual for a thorough description of response activities.

ACS acts as a facilitator for much of the research and development related to responding to spills in the Arctic. Research focuses on recovery techniques in, on, and under ice, and during various broken ice conditions, as well as detecting and tracking oil under ice, tundra treatment, high volume skimmers, ground penetrating radar and alternative response options (ACS 2010b). ACS also manages research and development projects for BP Exploration, Inc., and ConocoPhillips Alaska, Inc., to meet the requirements to the Charter for Development of the Alaskan North Slope commitment to the State of Alaska. ACS is working with BOEMRE on improving methods for recovering residues of in-situ burning techniques of marine oil spills (ACS 2010b).

8. Cleanup and Remediation

The state's priorities for oil spill responses are as follows:

- Safety of all persons involved in the spill;
- Protecting public health from contamination of drinking water, air, and food;
- Protecting the environment, natural and cultural resources, and biota from direct and indirect effects of contamination;
- Ensuring adequate containment, control, cleanup, and disposal by the responsible party, leading to the state assuming control of the incident, if necessary;
- Assessing contamination and damage and restoration of property, natural resources, and the environment; and
- Recovering costs and penalties (ADEC 1999; ADEC 2007a)

Cleanup plans, regardless of the location and nature of the spill, must balance the objectives of maximizing recovery and minimizing ecological damage. All oils are not the same, and knowledge of the chemistry, fate, and toxicity of the spilled oil can help identify cleanup techniques that can reduce the ecological impacts of an oil spill. Hundreds of laboratory and field experiments have investigated the fate, uptake, toxicity, behavioral responses, and population and community responses to crude oil.

Plans must also address the complications of working in Arctic conditions including extreme cold, ice, and darkness. The North Slope and North Slope Foothills areas can present extremes that might make it difficult to effectively contain and clean up a major spill. Cold weather, in particular, can challenge both personnel and machinery. Conversely, ice and snow can act as natural barriers and facilitate clean up (ADEC 1999, ADEC 2007a). However, spills that occur during the summertime risk impacting the diverse species that use North Slope Foothills habitats. Plans address specific steps to accommodate these conditions. The effects on the sensitive environments of the region could be severe if they are not mitigated.

9. Fate and Behavior of Spilled Oil

Quick response and recovery greatly affect the efficacy of any spill cleanup. After a spill, the physical and chemical properties of the individual constituents in the oil begin to be altered by the physical, chemical, and biological characteristics of the environment. These are called weathering, spreading, evaporation, dispersion, dissolution, and emulsification (BLM 2008a). Evaporation allows lighter components of oil to evaporate; evaporation increases as oil spreads and in rougher seas and higher temperatures. Dispersion on water occurs when waves and turbulence break up the oil slick into droplets and smaller slicks. Droplets may remain in the water column or rise to the surface and combine with other droplets to form a new slick. Dissolution is the process wherein

water soluble compounds dissolve into water. The passage of time before the start of recovery allows oil to spread, expanding the affected area and thus requiring more response resources. The longer the oil remains exposed to the elements the more weathered it becomes, making it more viscous and more likely to form water in oil emulsions that can limit the effectiveness of skimmers, increase storage requirements on water, and negatively impact the oil's ability to burn (MMS 2008).

Oil on water spreads and quick intervention is critical. The fate and behavior of oil spilled in Arctic waters could be affected by the presence or developing presence of ice. Evaporation is the only significant weathering process at the time of freeze-up. Oil under ice may be trapped, or encapsulated, and will not evaporate; as ice melts in the spring, the oil rises to the surface and, if the ice moves, oil will appear at a different location than the spill (NRC 2003). Broken ice promotes emulsification more rapidly than open water (NRC 2003).

Upland spills follow topography; oil flows downhill. If released to tundra, summertime spills penetrate soil and foul tundra. Wintertime spills may be constrained, or facilitated, by snow and ice. Ice can also prevent oil from spreading.

The factors that are most important during the initial stages of cleanup are the evaporation, solubility, and movement of the spilled oil. As much as 40% of most crude oils may evaporate within a week after a spill. Over the long term, microscopic organisms (bacteria and fungi) break down oil (Jorgenson and Cater 1996). Understanding these processes is critical to decisions about cleaning spilled oil.

10. Cleanup Techniques

The best cleanup techniques are those that quickly remove volatile aromatic hydrocarbons. This is the portion of oil that causes the most concern regarding the physical fouling of birds and mammals. To limit the most serious effects, it is desirable to remove the maximum amount of oil as soon as possible after a spill. The objective is to promote ecological recovery and not allow the ecological effects of cleanup to exceed those caused by the spill itself. Table 6.4 lists cleanup objectives and techniques that may be applicable to each objective. Table 6.5 compares the advantages and disadvantages of cleanup techniques for crude oil in terrestrial and wetland ecosystems (Jorgenson and Cater 1996).

Cleanup phases include initial response, remediation, and restoration. During initial response, the responsible party: gains control of the source of the spilling oil; contains the spilled oil; protects the natural and cultural resource; removes, stores and disposes of collected oil; and assesses the condition of the impacted areas. During remediation, the responsible party performs site and risk assessments; develops a remediation plan; and removes, stores, and disposes of more collected oil. Restoration attempts to reestablish the ecological conditions that preceded the spill and usually includes a monitoring program to access the results of the restoration activities (Jorgenson and Cater 1996).

Spill recovery techniques are generally considered mechanical (e.g., boom and skimmers) or nonmechanical (in-situ burning and dispersants); one or more techniques may be used together. The location of the spill (open water, protected water, on land, wetlands, broken ice) and weather are critical factors determining the techniques employed (ACS 2008).

Containment booms used in conjunction with skimmers are the most commonly used mechanical method for removing oil from water. Booms float on water and corral the oil and then skimmers are used to remove the concentrated oil. Some booms have been adapted for use in icy waters (NRC 2003). Skimmers of choice for Arctic waters are oleophilic brush, rope mop, or drum/disc skimmers that collect oil when it adheres to the surface of the brush or rope (MMS 2008). Oil is then scraped off into a sump and pumped to a storage tank. These skimmers efficiently recover oil while limiting

the amount of water collected, extending storage on water, but containment and recovery may be slow and may not remove all the oil.

Dispersants and in-situ burning are nonmechanical techniques. Dispersants chemically treat oil while it floats on the water surface. Dispersants do not remove the oil, but break it into very small droplets that mix into the upper water column, promoting rapid degradation. In Alaska dispersants are only used to clean up spills on water and are not used on broken or solid ice (ADEC 2007a). Use of dispersants must be approved in advance in certain coastal areas, by the Unified Command and by the EPA. Choosing dispersants as a recovery technique is influenced by water depth and distance from the shoreline; its use usually is not permitted in areas where the water depth is less than 10 meters (MMS 2008).

In-situ burning involves collecting or concentrating oil, performing a controlled burn, and then removing the residue. It is most effective when used early in the cleanup process, before oil has emulsified. On open water, this technique may involve special booms, igniting agents, and methods to deliver them. Burning can be effective in the Arctic, where ice may help contain a spill. ADEC's revised burning guidelines function as ARRT's policy on in-situ burning and present the required Federal and State On-Scene Coordinators approval process (ADEC 2008). MMS considered in-situ burning the preferred method of non-mechanical response for icy waters (MMS 2008).

Table 6.4. Objectives and techniques for cleaning up crude oil and terrestrial and wetland ecosystems.

Objectives	Cleanup Techniques
Minimize:	
Movement of oil	Absorbent booms Sand bagging Sheet piling
Surface-water contamination	Same as above
Soil infiltration	Flood surface
Soil and vegetation contact and oil adhesion	Flood surface Use surfactants to reduce adhesion
Vegetation damage	Use boardwalks to reduce trampling Use flushing instead of mechanical techniques Perform work when vegetation is dormant
Thawing of Permafrost	Avoid vegetation and surface disturbance
Wildlife contact with oil	Fencing to prevent wildlife from entering site Plastic sheeting to prevent birds from landing on site Guards to haze wildlife Devices to haze wildlife
Acute and chronic toxicity of oil to humans, fish, and wildlife	Removal of oil Enhance biodegradation of remaining oil
Waste disposal	Use flushing Avoid absorbents and swabbing
Cost	Remove oil as fast as possible Achieve acceptable cleanup level quickly to minimize monitoring
Liability	Achieve acceptable cleanup level
Maximize:	
Recovery potential of tundra ecosystems	All of the above Add nutrients to aid recovery of plants
Worker safety	Air testing, training, clothing

Source: Jorgenson and Cater 1996.

Table 6.5. Advantages and disadvantages of techniques for cleaning up crude oil in terrestrial and wetland ecosystems.

Technique	Advantage	Disadvantage	Recommended
Wildlife			
Fencing	Keeps out large mammals	Does not keep out birds	Yes
Plastic sheeting	Keeps out both birds and mammals	Can no longer work area	Sometimes
Wildlife guard	Flexibility to respond	Higher cost	Sometimes
Devices	Lower cost	Animals become habituated	No
Containment			
Absorbent booms	Contains floating oil, quickly deployed	Misses water soluble oil	Yes
Sand bags	Contains both floating and soluble fractions, follows tundra contours	Slower to mobilize, some leakage	Yes
Sheet piling	Maximum containment	Slow to install, doesn't fit contours well	Sometimes
Earthen berms	Can easily be adapted to terrain, heavy equipment rapidly can create berms	Destroys existing vegetation and soil	No
Snow/ice berms	Can be used during winter cleanup or to prevent runoff during breakup	Can only be used during freezing periods	Yes
Contact			
Flooding	Keeps heavy oil suspended	Spreads out oil	Yes
Surfactants	Reduces stickiness, aids removal, and reduces volatilization	Reduces effectiveness of rope mop skimmer	Yes
Thickening agents	Untried, aids physical removal	Must be well drained, physical removal more difficult	No
Access			
Boardwalks	Reduces trampling	None	Yes
Removal			
Complete excavation	Eliminates long-term liability	Eliminates natural recovery, disposal costs	Sometimes
Partial excavation	Quickly reduces oil levels, less waste to dispose of than complete excavation	Causes partial ecological damage, disposal costs, still long-term liability	Sometimes
Burning	Low cost, high removal rate	Little testing, ecological damage	Sometimes
Flushing, high pressure	High removal rate	High ecological damage	No
Flushing, low pressure, cold	Moderate removal rate, little damage, easy waste disposal	Spreads oil, not as effective as warm water	No
Flushing, low pressure, warm	High removal rate, little vegetation damage, easy disposal of waste	Spreads oil	Yes
Aeration	Accelerates volatilization	Volatiles lost to air, may pose risk to humans	Yes
Raking	Can target hot spots	Partial vegetation damage	Sometimes
Cutting and trimming	Targets hot spots, reduces stickiness	Partial vegetation damage	Sometimes
Swabbing	Targets hot spots	Not very effective, adds to waste disposal, adds to trampling	No
Oil skimmers and rope mops	Removes heavier oil, works well with flooding, lowers disposal costs	Requires personnel to push oil to skimmer, adds to trampling	Yes
Vacuum pumping	Removes surface and miscible oil, works well with flooding, lowers disposal cost	None	Yes
Biodegradation	Removes low levels of hydrocarbons, non- destructive, lowers disposal costs	Long-term monitoring, site maintenance, may require wildlife protection	Yes

Source: Jorgenson and Cater 1996.

Burning rapidly removes oil from the environment, particularly when compared to water shoreline cleanup activities that may take months or even years. The principle disadvantages of using in-situ burning are smoke plumes and the narrow timeline associated with it. Oil is most volatile before it evaporates or emulsifies, so waiting too long makes in-situ burning ineffective. Burning may also leave toxic residues. If they sink, they may be ingested by the species that use the waters. However, residue cools slowly, allowing time to recover it (ADEC et al. 2008). Samples collected after the

Newfoundland Offshore Burn Experiment were tested for toxicity to three aquatic species. Neither the residue nor the oil was toxic and the burn residue was no more toxic than the oil itself (ADEC et al. 2008). ADEC's guidelines require that approved burns have a plan for residue collection.

State regulations require that operators be able to mechanically entrain and recover, within 72 hours, a response planning standard (RPS) volume of oil (18 AAC 75.434). For exploration facilities, the RPS is a minimum of 16,500 bbl plus 5,500 bbl for each of 12 days beyond 72 hours. For production facilities, the RPS is, at a minimum, 3 times the annual average daily production for the maximum producing well at the facility. If well data demonstrate a lower RPS is appropriate, it may be adjusted accordingly. Conventional booms and skimmers have difficulty working efficiently among the broken ice (ADEC 2007b).

The federal, state and local statutes and regulations that apply to the regulation of oil spill prevention and response are included in Chapter Seven, Governmental Powers.

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