Chapter Six: Oil and Gas in the Beaufort Sea

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Chapter Six: Oil and Gas in the Beaufort Sea

A. Geology

The lease sale area contains acreage that is located in the Arctic Coastal Plain region within the North Slope Structural Province. The North Slope Structural Province forms the modern northern continental margin of Alaska.

The geologic history of the lease sale area includes periods of plate collisions, continental rifting, regional uplift, episodes of major regional erosional scour, and sedimentary deposition. Northern Alaska has four major geologic sequences of rocks, each having a unique structural setting, provenance (sediment source area), and depositional environment. During the deposition of each of these major geologic sequences, smaller scale events, such as changes in sea level and differential amounts of basin subsidence, have altered and shaped the depositional environments, sculpturing local internal complexities within each of the four major sequences. The four major rock sequences from oldest to youngest (older rocks are deposited first and in the absence of structural complexities are stratigraphically lower): the Franklinian, Ellesmerian, Beaufortian Rift, and the Brookian. The structural events that shaped the evolution of the North Slope Structural Province were (Figure 6.1):

1. A stable early continental platform before Devonian time;
2. Onset of continental rifting during the Late Jurassic through Early Cretaceous time, with uplift to the north of this stable Arctic Platform and deposition of sediments southward; and
3. Continued rifting, uplift, and termination of deposition from the north, along with uplift of the Brooks Range and deposition of sediments from the south onto the Arctic Coastal Plain during the Early Cretaceous through Tertiary time.

The Franklinian (pre-Mississippian) sequence was once a stable continental platform before Middle Devonian time (about 400 million years ago). Pre-Mississippian rocks of the Franklinian sequence comprise the oldest rock sequence that underlies the Arctic Coastal Plain region. The Franklinian sequence consists of fractured carbonate, argillite, quartzite, volcanic, and granitic rocks that were deformed, uplifted, and eroded during Cambrian through Devonian time. During the Late Devonian time, the Franklinian sequence was uplifted. Erosion off the uplifted Franklinian high provided the northerly source of sediments for the Ellesmerian sequence. The highly metamorphosed and fractured rocks of the Franklinian sequence have limited petroleum potential, most likely only as fractured reservoirs.

The Ellesmerian sequence contains marine carbonates and quartz- and chert-rich clastic rocks that were deposited over a 150 million year period on a subsiding foldbelt terrain during the Mississippian through Early Jurassic time. The Ellesmerian thins to the south due to depositional distance from its source and thins to the north due to subsequent uplift and erosion (Moore et al. 1994). The Permo-Triassic Ivishak Formation was deposited within the Ellesmerian sequence as a large fan-delta complex. It forms the reservoir for the giant Prudhoe Bay Oil Field that has produced over 12 billion bbl of oil.

The modern northern continental margin of Arctic Alaska has been shaped by structures that were formed as a result of Jurassic to Early Cretaceous rifting events that created the Barrow Arch, a structural high that has dominated the structural and depositional history of the area (Moore et al. 1994). Rifting of the continental mass dominated the geology of the North Slope by the end of the late Jurassic to late Cretaceous periods. The northern continental source for the Ellesmerian sediments

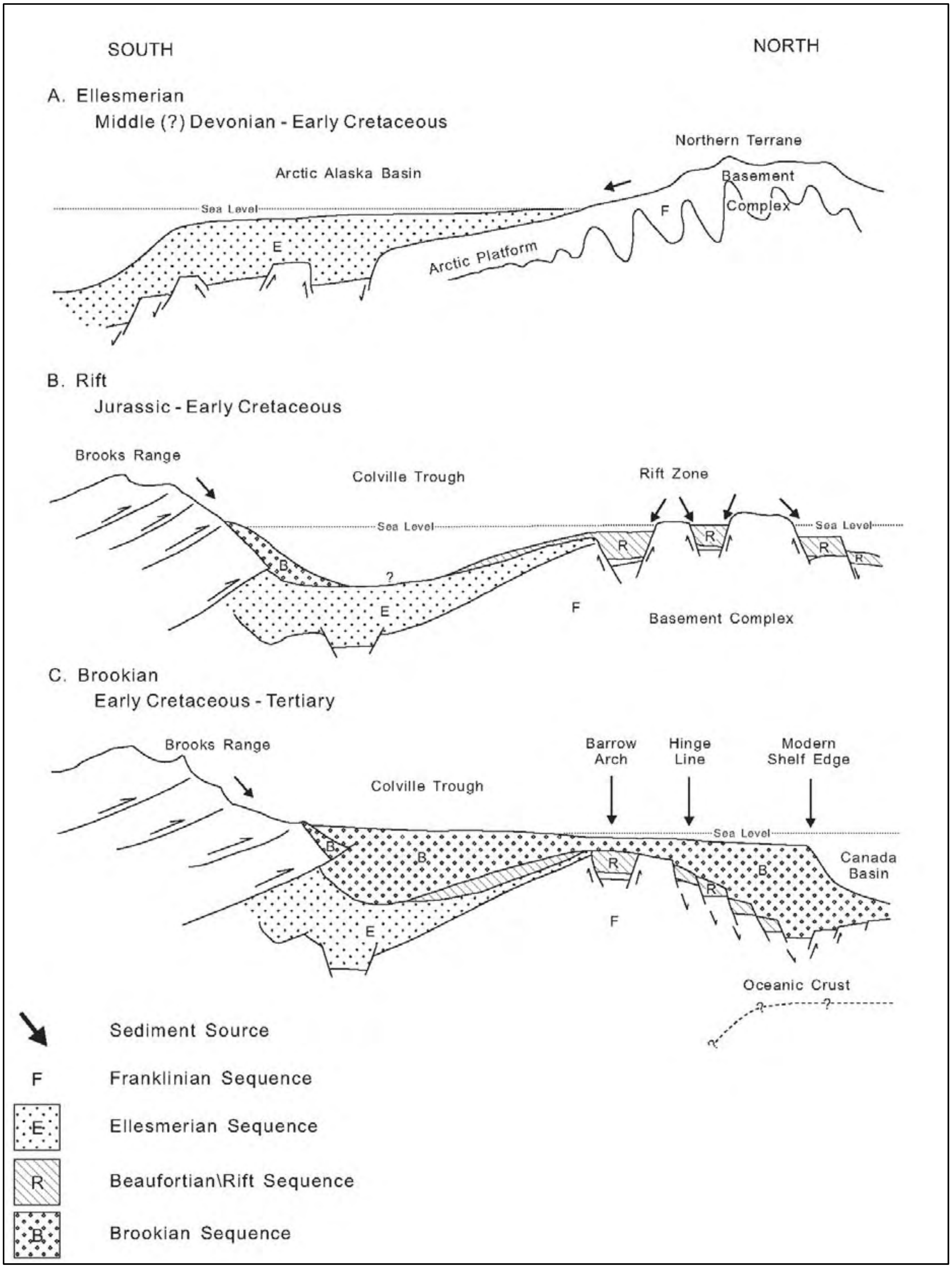


Figure 6.1. Evolution of North Slope geology.

supplied less and less sediment to the Arctic Basin as time passed. Uplift and faulting of the Franklinian and Ellesmerian sequence formed normal fault blocks, consisting of horst and grabens. The grabens were filled with sediments from nearby locally uplifted or block-faulted Ellesmerian and Franklinian sequences, forming the Beaufortian Rift sequence (Craig et al. 1985). At this time, the Barrow Arch formed along the present day Beaufort Coast. Sedimentation from the north eventually ended in the Late Cretaceous.

The following period of non-deposition along with continued uplift along the Barrow Arch created a regional scouring event known as the Lower Cretaceous Unconformity (LCU), which becomes angular where approaching the Barrow Arch from the south. Ellesmerian strata were progressively uplifted, subaerially exposed, eroded, and truncated in a northeasterly direction along the emerging Barrow Arch during the Late Jurassic and Early Cretaceous. The LCU stripped off significant amounts of Ellesmerian strata and resulted in the creation of enhanced porosity, creating excellent hydrocarbon reservoirs in the formations that lay directly under this angular unconformity. The regional erosional activity of the LCU is one of the most significant geological events with regards to the creation of secondary porosity in potential reservoir rocks as well as creating a conduit for the migration of oil and gas into these enhanced porosity reservoirs. In general, the Ellesmerian formations that are prolific oil producers such as the Kuparuk ‘A’ Sandstones and the Ivishak and Kekiktuk formations, directly underlie the LCU.

Following the uplift and erosion of the Ellesmerian section by the LCU along the Barrow Arch, the Arctic Coastal Plain was buried by marine shales, siltstones, and sandstones of the Beaufortian Rift sequence. Oil and gas traps within the Beaufortian Rift sequence include purely stratigraphic traps as well as combination structural/stratigraphic traps that were formed by the sequence of rift events. Many of the Beaufortian Rift sandstones that directly overlie the LCU such as the Kuparuk ‘C’ and Alpine sandstones are prolific North Slope oil reservoirs. The rift-derived sediments of the Beaufortian Sequence contain many known oil and gas accumulations (Map 6.1) such as the Kuparuk River, Milne Point, Pt. McIntyre, Niakuk, Alpine, and Pt. Thomson fields as well as discoveries in the Colville Delta area such as the Texaco Colville Delta, Fiord, and Kalubik wells. Known gas accumulations are present within this interval in NPR-A with the East Barrow, South Barrow, Sikulik, and Walakpa fields.

Since the formation of the continental margin in the Early Cretaceous, the northern flank of the Barrow Arch has been dominated by passive-margin subsidence and sedimentation. To the south, compressional forces in the Jurassic to Early Cretaceous caused thrust faulting in what is now the present-day Brooks Range. Sediments from the thrust-faulted blocks in the Brooks Range poured into the Colville basin, progressively filling it from the south, forming the Brookian sequence. The post Albian Brookian sequence records the progressive filling of a large east-west trending foreland basin (the Colville Trough) formed in response to thrust loading from the Brooks Range, a large north vergent fold and thrust belt. During latest Cretaceous and Paleocene time, deposition of Brookian sediments filled the Colville Trough, eventually overstepping the Barrow Arch and spread out onto Alaska’s continental margin. Petroleum accumulations in the Brookian sequence are found throughout the North Slope basin. Fields and hydrocarbon accumulations include: the West Sak, Schrader Bluff, Ugnu, Flaxman Island, Badami, and the Outer Continental Shelf (OCS) accumulation at Hammerhead (Weimer 1987).

The onshore present-day geology of the lease sale area is comprised of a thick section of unconsolidated Quaternary sediments (Brown and Kreig 1983) that have been deposited within the last million years. These sediments comprise the Gubik Formation that unconformably overlie the weakly cemented sediments of the upper Brookian sequence. Most Quaternary deposits are unconsolidated sand and gravel composed of reworked Brookian sediments and reworked sediments from the present day Brooks Range. Overlying these deposits are gravels, sands, ice-rich silts, and sandy silts (that include variable amounts of organic matter) that are deposited by the numerous rivers on the North

Slope. In addition to the extensive fluvial deposits, there are local areas of modern eolian deposits (sand dunes) that are derived from river silts (Brown and Kreig 1983).

During middle to late Devonian time, a mountain building and rifting event uplifted the Franklinian sequence, deforming and metamorphosing the rocks in the process. Sediments from the uplifted Franklinian sequence spread southward into the large arctic basin (epicontinental shelf). This process continued through to late Cretaceous time. These northerly sourced sediments formed the Ellesmerian sequence (Moore et al. 1994).

The Ellesmerian sequence is the most important geologically in terms of petroleum production. Formations within the Ellesmerian sequence form the primary petroleum reservoirs at Prudhoe Bay, and Endicott. The Ellesmerian sequence contains marine carbonates and quartz and chert rich clastic rocks, representing about 150 million years of deposition (Mississippian through Triassic). From the center of the Colville Basin, the Ellesmerian thins to the south due to depositional distance from its source and it thins to the north due to subsequent uplift and erosion (Moore et al. 1994).

Rifting of the continental mass dominated the geology by the end of the late Jurassic to late Cretaceous periods. The northern continental source for the Ellesmerian sediments supplied less and less sediment to the arctic basin as time passed. Uplift and faulting of the Franklinian and Ellesmerian sequence formed fault block and grabens (low areas between fault blocks). These grabens were filled by sediments from the locally uplifted or upfaulted Ellesmerian and Franklinian sequences, forming the Rift sequence (Craig et al. 1985). It is also at this time that the Barrow Arch formed along the present day Beaufort Coast. Sedimentation from the north eventually ended sometime in the Late Cretaceous and the following period of non-deposition along with continued uplift along the Barrow Arch created a regional Lower Cretaceous Unconformity (LCU) that becomes angular approaching the Barrow Arch from the south. To the north of the Barrow Arch the Ellesmerian sequence is absent. The LCU is an important migration and accumulation element for most of the oil fields on the North Slope including Prudhoe Bay (Jamison et al. 1980).

To the south, compressional forces in the Jurassic to early Cretaceous caused thrust faulting in what is now the Brooks Range. Sediments from the thrust-faulted blocks in the Brooks Range poured into the Colville Basin, progressively filling it from the south, forming the Brookian sequence. Brookian sediments filled the Colville Basin and spread out over the Barrow Arch and onto Alaska's continental margin during the upper Late Cretaceous through Tertiary time. Petroleum accumulations in the Brookian sequence are found throughout the North Slope basin, including at West Sak, Schrader Bluff, Flaxman Island, and the Outer Continental Shelf (OCS) accumulation at Hammerhead (Weimer 1987).

Onshore present day geology of the lease sale area is, in general, comprised of a thick section of unconsolidated Quaternary sediments (Brown and Kreig 1983), deposited within the last 1 million years. These sediments are probably of the Gubik Formation, which unconformably overlies the weakly cemented sediments of the upper Brookian sequence. Most Quaternary deposits are unconsolidated sand and gravel composed of reworked Brookian sediments, along with materials from the present day Brooks Range. Overlying these deposits are ice-rich silts and sandy silts (1.5 m to 2.5 m thick at Prudhoe Bay) that include variable amounts of organic matter, which are deposited by the numerous rivers on the North Slope. In addition to these fluvial deposits are local areas of eolian deposits (sand dunes) derived from river silts (Brown and Kreig 1983).

B. Petroleum Potential

ADNR has determined that the lease sale area, in general, has moderate to high petroleum potential. This represents ADNR's assessment of the oil and gas potential of the area and is based on a resource evaluation made by the state. This resource evaluation involves several factors including geology, seismic data, exploration history of the area, and proximity to known hydrocarbon accumulations.

In order for an accumulation of hydrocarbons to be recoverable, the underlying geology must be favorable. This may depend on the presence of source and reservoir rock; the depth and time of burial; and the presence of migration routes and geologic traps or reservoirs. Source rocks are organic rich sediments, generally marine shales, which have been buried for a sufficient time, and with sufficient temperature and pressure to form hydrocarbons. As hydrocarbons are formed, they will naturally progress toward the surface if a migration route exists. An example of a migration route might be a permeable layer of rock in contact with the source layer, or fractures that penetrate organic rich sediments. A hydrocarbon reservoir is permeable rock that has been geologically sealed at the correct time to form a "trap." The presence of migration routes therefore affect the depth and location where oil or gas may pool and form a reservoir. For a hydrocarbon reservoir to be producible, that is, economic, the reservoir rock must be of sufficient thickness and quality (good porosity—number of pore spaces per volume, and permeability—a rock's capacity for transmitting a fluid), and must contain a sufficient volume or fill of hydrocarbons.

The Beaufort Sea has all these favorable geologic conditions and, considering the exploration history of the area, the chances of finding undiscovered petroleum reservoirs are very good. However, the remaining undiscovered reservoirs are expected to be non-economic to marginally economic accumulations under current market conditions. In light of this, the petroleum potential of this basin for the discovery of new fields is moderate.

The process of evaluating the oil and gas potential for state lease sale areas, such as the Beaufort Sea, involves the use of seismic data and well engineering information, which by law, the division must keep confidential under AS 38.05.035(a)(8)(C). In order to protect these data, the division must generalize the assessment, which is made public.

C. Phases of Oil and Gas Development

Lease-related activities proceed in phases, moving from leasing, to exploration, and then to development and production. Each phase's activities depend on the completion or initiation of the preceding phase. Table 6.1 lists 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, ADNR prepares and presents a 5-year program of proposed oil and gas lease sales to the legislature. Currently, 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 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. 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 received 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 any operations may be undertaken on or in the leased area, except for activities that would not require a land use permit or for operations undertaken under an approved unit plan of operations.

Although beyond the scope of this final 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 6.1. 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. In the offshore environment, surface analysis includes the study of surface topography or the natural surface features of the near-by coastal area; 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 Beaufort Sea lease sale area. Geophysical surveys, primarily seismic, help reveal what the subsurface geology may look like. Exploration of the Beaufort Sea Sale area has been ongoing since the first geologic and topographic studies were conducted in 1901.

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. ADNR tailors each permit approval 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

B. Havelock, DO&G

Example of vibroseis trucks conducting a seismic survey.

effects varies, depending on the survey method and the time of year the survey is conducted. Geophysical exploration activities are regulated by 11 AAC 96.

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, land and marine 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 structures and petroleum potential. Both 2-dimensional (2D) and 3-dimensional (3D) data are gathered from seismic surveys. In the Beaufort Sea lease sale area, seismic surveys are conducted on land, grounded ice, floating ice, and in open marine waters.

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 crewmembers and employ much less equipment than 3D programs.

Seismic data over coastal lands 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 ocean bottom cables in the summer months. Ice based seismic programs are dependent on ice pack thickness and stability, and are rarely executed farther out than the barrier islands. Collecting data in the winter months minimizes 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, airguns can be lowered through holes drilled in the ice to provide the acoustic energy. For marine surveys, towed airguns, or an array of several airguns, are used as the energy source.

Open water surveys are conducted in the summer, ice free, months. Marine surveys use a towed energy source, and can use either towed receivers (streamer cables) or ocean bottom cables (OBC surveys) where the cables containing the geophones and hydrophones lay directly on the sea floor. Marine seismic programs typically use a vessel between 100-175 feet long. Shore-based helicopters, which can land on the vessel's helideck, resupply the operation and transfer crew when necessary. Seismic equipment consists of an airgun array for the energy source, hydrophones (and sometimes geophones) to detect reflected sound energy, an amplifier and recording system, and a navigation system. The airgun array, towed directly behind the ship at a depth of 30 to 40 feet (or shallower if required by water depth), consists of several sub-arrays, each containing several airguns of various sizes. Hydrophones and geophones are housed in long streamer cables (1-2 miles), which are towed behind the ship at depths between 20 and 40 feet. For 2D surveys, one cable is towed at a time. For 3D surveys, multiple cables can be towed. For OBC seismic surveys, the detectors and cables are placed directly on the bottom where they remain stationary as the shooting boat traverses across them. In addition to ice hazards, the season can be also be limited by protections for fishing, wildlife, marine mammals, and subsistence hunting.

Additional geophysical techniques can be used to gather information specifically about the ocean bottom and 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 ocean bottom and very shallow geology. They employ smaller vessels, 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 reveals 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 is 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 completed, suspended or is plugged and abandoned.

When directionally drilling from onshore, 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 sand and gravel placed over a liner and is about 300 feet by 400 feet. 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 the 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 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).

Offshore exploratory drilling rigs include bottom-supported rigs such as submersibles and jackup rigs, barges, floating rigs such as drill ships, and semi-submersibles. In shallow water an ice island or gravel island may be constructed and, on occasion, a barrier island may be used to drill offshore. Island drilling is a function of both depth and environmental conditions. Water depth and bottom conditions determine which equipment will be used. Some mobile offshore drilling units (MODUs) that may be used during the exploration phase, their support types, and operational depths are listed below:

- Bottom supported
  - Submersibles
    - Posted barges (water <30 feet)
    - Bottle-type submersibles (water <200 feet)
    - Arctic submersibles (concrete island drilling system (CIDS; water up to 150’)
  - Jackups
    - Columnar legs (water 300’ to 600’)
    - Truss legs (water 300’ to 600’)
  - Inland barges (shallow water)
  - Ship-shaped barges and drill ships
- Semi-submersibles (deep-water applications).

When a prospect cannot be reached using directional drilling (Appendix C) from shore, an arctic rated rig and support facility are most likely to be used in the Beaufort Sea for exploratory wells, as they are best suited for sometimes shallow water locations and can withstand currents, ice buildup, and tidal variations experienced there. These rigs may have watertight barge hulls that can float on the surface of the water while the unit is being moved between drill sites. Some units are towed while others are self-propelled. Some types of drilling rig facilities are bottom founded while others may be mounted on a ship or jackup platform. Sometimes drilling will be done from a man-made island or a natural barrier island if conditions allow. Before the location is finalized, the operator performs a geological hazards survey to make sure that the sea floor can support the rig. High-resolution shallow seismic surveys look for shallow gas (methane) deposits and faults. When the rig facility is positioned at the drill site, it will be affixed to the site either by legs jacked from the seafloor, positioned dynamically if floating or landed on the seafloor if in shallow water. Depending on the type of drilling facility, the drilling topsides are positioned to accommodate ice, tides, and waves.

An exploratory drilling operation generates approximately 12,000 cubic feet of drilling cuttings. Cuttings 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 (Gerding 1986). 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. The mud cools and lubricates the drill bit, prevents the drill pipe from sticking to the sides of the hole, seals off cracks in down-hole formations to prevent the flow of drilling fluids into those formations, and carries cuttings to the surface.

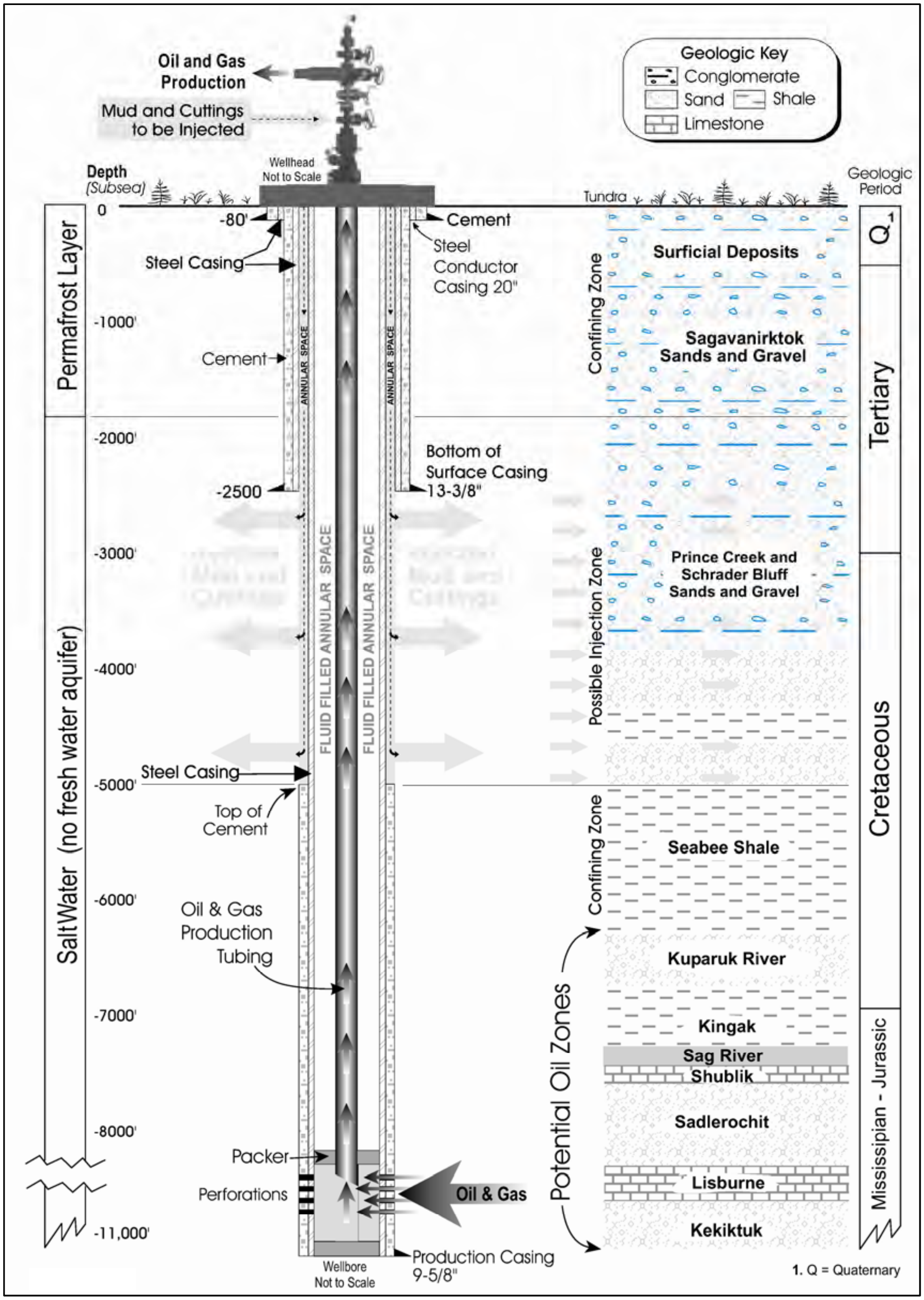
Disposal of mud, cuttings, and other effluent is regulated by the National Pollutant Discharge Elimination System (NPDES) and the EPA’s Underground Injection Control program administered by the Alaska Oil and Gas Conservation Commission under regulations in 20 AAC 25. The state discourages the use of reserve pits, and most operators store drilling solids and fluids in tanks or in temporary on-pad storage areas until they can be disposed of, generally down the annulus of the well or in a disposal well that is completed and equipped to take mud and cuttings, and permitted in accordance with 20 AAC 25.080 and 20 AAC 25.252. If a reserve pit is necessary, it is constructed off the drill pad and could be as large as 5 feet deep and 40 feet by 60 feet. It is lined with an 80-mil geotextile liner to prevent contamination of surrounding soils. 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. 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.

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

The development and production phases are interrelated and overlap in time; therefore, this section discusses them together. 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. These phases can begin only after exploration has been completed and tests show that a discovery is economically viable (Gerding 1986).

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 6.2 depicts a typical wellbore. The development “footprint” has decreased in recent years as advances in drilling technology have led to smaller, more consolidated pad sizes. Directional drilling (Appendix C) allows more wells to be drilled from a common location (drill pad). A single production pad and several directionally drilled wells can develop more than one and possibly several 640-acre sections.



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 6.2. Typical production/injection well, North Slope, Alaska.

K. Marsh, DO&G

Prudhoe Bay.

The Northstar Field has been developed from a man-made offshore island of approximately 5 acres (Ragsdale 2007). The reservoir area covers nearly 10,000 acres (about 16 - 640 acre sections) The Oooguruk Field is based on an offshore man-made island of approximately 6 acres (Lidji 2008). Footprints at these two fields compare with the first Beaufort Sea development at the Endicott Field, which was developed from two islands linked by a causeway that cover approximately 47 acres in total (Nelson 2000b). The Liberty Field will be developed from the Endicott SDI, which will be enlarged to accommodate additional wells.

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 are being 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.

The Alaska Oil and Gas Conservation Commission 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. It is a quasi-judicial agency, which conducts hearings to review drilling and development to ensure regulatory compliance. The Commission 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.

4. Subsurface Oil and Gas Storage

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.

North Slope gas is now used to support production of oil and gas on the North Slope. When a gas pipeline is constructed from the North Slope to market, gas will also be transported to market. Subsurface storage of gas increases reliability of gas delivery to all sources of demand.

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 gas cushion (or base gas requirements). It also depends on access to transportation, pipeline infrastructure, existing production infrastructure, gas production sources, and delivery points.

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, specifically 20 AAC 25.252. Before any gas may be injected, approval of the Injection Order from AOGCC must be obtained.

Some unproduced “native” gas may remain in gas storage reservoirs and serve as “cushion gas” to support gas withdrawal and delivery rates. Cushion gas is the volume of gas intended as permanent inventory in a storage reservoir to maintain adequate pressure and deliverability rates throughout the withdrawal season. Royalty on this native 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.

ADNR may amend a subsurface storage authorization if stored gas migrates from the gas storage formation to other formations or if stored gas expands beyond the limits of the authorized area. DO&G shall be notified of any anticipated changes in the project resulting in alteration of conditions that were originally approved and further approval must be obtained before those changes are implemented.

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Meade River test well 1 derrick. Barrow district, Northern Alaska region, Alaska. April 17, 1950.

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.

D. Oil and Gas Exploration, Development, and Production in the Beaufort Sea

1. History of Oil and Gas on the North Slope and in the Beaufort Sea

Oil seeps have long been known to the Inupiat people of the North Slope, who excavated tar-saturated tundra for use as fuel within historic time. Following reports of oil seeps along the coast by early traders, the first geologic and topographic studies were conducted in 1901 and the first formal descriptions were recorded by the U.S. Geological Survey (USGS) in 1919. By 1921, prospecting permits were filed and in 1923, President Harding established the Naval Petroleum Reserve No. 4 (NPR-4) by executive order. The USGS conducted reconnaissance mapping from 1923 through 1926 and published the results in 1930 (Jamison et al. 1980; AEIDC 1975).

The first exploration phase of NPR-4 ended in 1953. Between 1923 and 1953, the United States Navy drilled 37 test wells and found three oil accumulations and six gas accumulations within and adjacent to the reserve. Only two of these discoveries were considered sizable, namely Umiat, with an estimated 70 million bbl of recoverable oil, and Gubik (partly outside the reserve), with an estimated 600 billion cubic-feet of recoverable gas (Molenaar 1982; Kumar et al. 2002). Gas from another of the discoveries, the small South Barrow gas field, is being produced today for local consumption at Barrow.

BLM opened North Slope lands for competitive bidding in 1958 when 16,000 acres were offered in the area of the Gubik gas field. That same year BLM opened 4 million acres in an area south and southeast of NPR-4 for simultaneous filing and subsequent drawing. From 1962-1964 industry exploration programs expanded rapidly. During this period, Sinclair and British Petroleum drilled a total of seven unsuccessful wildcat wells in the Arctic foothills (Jamison et al. 1980).

In 1964, under the Statehood Act, the state of Alaska selected some 80 townships across the northern tier of lands between the Colville and Canning Rivers and received tentative approvals on the 1.6 million acres from the federal government in October of the same year. In December 1964, the state held the 13th State Competitive Sale (the first on the North Slope) of leases covering 625,000 acres in the area east of the Colville River delta. In July 1965, the state held the 14th State Competitive Sale, which included the onshore area in the vicinity of Prudhoe Bay. In the 18th State Competitive Sale, held in January 1967, the offshore Prudhoe Bay tracts were offered and leased (Jamison et al. 1980).

Following the succession of dry holes in the Arctic foothills, exploration shifted northward to the central coastal area. In 1965, the first holes drilled in the area immediately surrounding the Prudhoe Bay structure came up dry. In January 1967, in what was essentially a last-ditch effort, a rig was moved to the Prudhoe Bay State No. 1 location near the mouth of the Sagavanirktok River. Twelve months later the discovery of the Prudhoe Bay oil field was announced (Jamison et al. 1980; AEIDC 1975). Prudhoe Bay field began production in 1977 and, with its satellite fields (Map 6.1), is currently estimated to have originally contained in excess of 15 billion bbl of economically recoverable oil, making it the largest oil field ever discovered in North America.

Following the Prudhoe Bay discovery, exploration activity increased dramatically. Thirty-three exploration wells were completed in 1969, as industry prepared for the Lease Sale 23 in September of that year. The state offered 413,000 acres along the Arctic coast between the Canning and Colville Rivers and earned more than $900 million in bonus bids on 164 tracts (Weimer 1987; Jamison et al. 1980). One significant find that came out of this increased activity was the discovery of the Kuparuk River field. In the spring of 1969, the Sinclair Ugnu No. 1 well tested oil from the Kuparuk Formation at a rate of 1,056 bbl of oil per day (Masterson, 1992). Subsequent delineation proved the field to contain 1 billion bbl of recoverable oil. Production at Kuparuk began in December of 1981, and current estimates place the ultimate recovery of oil from the field at more than 2.6 billion bbl, including satellite accumulations (Nelson 2007b). The 1969 sale was the last lease sale on the North Slope until the joint federal-state sale in December 1979. After the discovery of the Prudhoe Bay field and before the 1979 joint sale, more than 100 exploratory wells were drilled on the North Slope, with 19 of those wells discovering oil or gas.

In 1974, spurred by the OPEC oil embargo of 1973, the federal government began a second large exploration program in NPR-4, which was re-designated the National Petroleum Reserve-Alaska (NPRA) in 1976. Between 1974 and 1981, the USGS drilled a total of 27 test wells within NPRA. Other than two additional gas fields that are currently being produced to supply Barrow, no commercial deposits were discovered by this program. The two currently producing fields are the Walakpa field, which contains an estimated 142 billion cubic feet of economically recoverable gas (Imm 1996), and the East Barrow field, which contains an estimated 13 billion cubic feet of economically recoverable gas (Kornbrath 1995). In 1980, Congress authorized competitive leasing within NPRA. From 1982-1984, four lease sales were held. A total of more than 1.3 million acres were leased in the first three sales, generating over $84 million in total bonus bids. The final sale received no bids. Only one industry well was drilled on a lease acquired in these sales. This well, the ARCO Brontosaurus No. 1, was completed, plugged, and abandoned in 1985.

The 1994 discovery of the giant field in previously unknown Jurassic sandstones on the northeastern border of NPRA demonstrated that the area contained significant untapped potential for commercial oil and gas accumulations. The field began production in late 2000, and is currently estimated to contain 429 million bbl of economically recoverable oil (Nelson 2000a). The discovery and subsequent development of the Alpine field has spurred renewed interest in the oil and gas potential of NPRA, west of the Colville delta, as well as the exploration and potential development of similar places in the Colville delta area.

Since the 1979 joint sale, five federal lease sales have been held in the Beaufort Sea, and there have been 28 state lease sales offering both onshore and submerged Beaufort Sea acreage. To date, 31 exploratory wells have been drilled in the federal waters of the Beaufort Sea, resulting in five discoveries: Seal Island/Northstar, Kuvlum, Hammerhead, Sandpiper, and Tern Island/Liberty. Exploration wells drilled through 2006 on North Slope state leases have resulted in 26 discoveries.

It is not surprising that many of these accumulations were found in the vicinity of Prudhoe Bay and Kuparuk, where the density of wells and seismic control is the highest and the geologic conditions optimal. At least eight of these post-Prudhoe Bay discoveries are currently producing oil because of the Prudhoe Bay infrastructure and their relatively close location to the trans-Alaska oil pipeline. Six of these, Lisburne, Kuparuk, Milne Point, Endicott, Niakuk, and Point McIntyre are major fields (Map 6.1). While initial production on the North Slope was from onshore areas, five fields, Endicott, Point McIntyre, Milne Point, Niakuk, and Northstar, produce at least some of their reserves from offshore areas.

The most recent development projects in the Kuparuk and Prudhoe fields have involved low-gravity oil sands (Shrader Bluff/West Sak, and Ugnu) that were primarily discovered in the Kuparuk River area in 1969. In the Kuparuk area, the West Sak sands alone contain an estimated 16 billion bbl of oil in-place and combined estimates for the West Sak and Ugnu area are as high as 40 billion bbl in-place (Werner 1987). Start-up of production of the West Sak occurred in 1997, with estimates that the initial pilot area contains 300-500 million bbl of economically recoverable oil (ADN 1996b). Low-gravity production from the correlative Schrader Bluff formation sands at the Milne Point field exceeded 20,000 bbl of oil per day on average by 2004 (AOGCC 2007). The geographic area over which this West Sak/Schrader Bluff resource occurs is extensive, and includes portions of the Kuparuk, Milne Point, and Prudhoe Bay units. Since the initial production at Kuparuk and Milne Point fields, the Prudhoe Bay field has begun its own Schrader Bluff oil projects in the western portion of the unit, called Orion and Polaris, and recent Schrader Bluff oil discoveries have been unitized to the northwest of Milne Point (Nikaitchuq) and southeast of Kuparuk (Rock Flour).

State lands east of Prudhoe Bay saw renewed exploration activity during the 1990s, yielding oil discoveries in Canning formation sandstones and the Sourdough and Yukon Gold prospects south of the Point Thomson field adjacent to ANWR. Current information indicates Sourdough could contain 100 million bbl of recoverable oil. The Sourdough project would require up to 35 miles of pipeline to link up with the Badami field (Staff 1997).

Oooguruk, located about northeast of Prudhoe Bay, is estimated to contain 100 million bbl of economically recoverable oil; Pioneer Resources constructed an island and pipeline in 2007-2008 and sold its first barrel of oil in June of 2008 (APRN 2008).

As of year-end 2008, 506 exploration wells have been drilled on state acreage in the North Slope and Beaufort Sea, with 407 lease tracts that have been drilled and 292 tracts that are or were under commercial development. There have been 31 exploration wells in the federal waters of the Beaufort Sea, resulting in five discoveries: Seal Island/Northstar, Kuvlum, Hammerhead, Sandpiper, and Tern Island/Liberty. Figure 6.3 shows the number of exploration wells drilled each year since 1944. Except for Northstar, which spans federal and state submerged lands, all of the region’s commercially producing fields are on state leases.

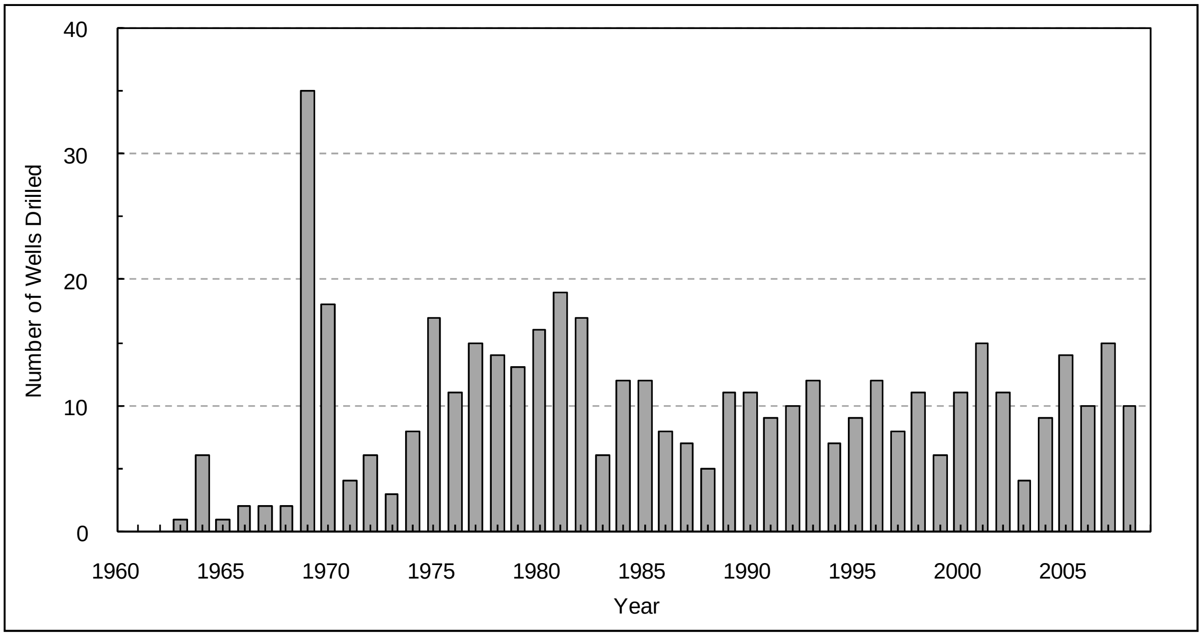

Figure 6.3. Alaska exploration well data, North Slope wells.

To date, over 30,000 miles of conventional (2-D) seismic surveys have been conducted on state acreage on the North Slope and in the Beaufort Sea. In addition, over 5,200 mi^2 of 3-D seismic surveys have been permitted in this region since 1985.

Table 6.2 lists the known oil and gas accumulations on state lands onshore and in state and federal waters. Six of the producing fields are offshore (Badami, Endicott, Milne Point, Niakuk, Northstar, and Point McIntyre; Map 6.1). However, all except Endicott, Northstar, Point McIntyre, and Oooguruk are being produced from directional wells drilled from onshore facilities. Both Endicott and Point McIntyre utilize causeways (Endicott also utilizes two artificial islands) to support offshore drilling and production facilities. In addition, BPX produces the Northstar Field totally from offshore facilities with winter ice roads for re-supply of consumable materials.

2. Proposed Development on the North Slope and in the Beaufort Sea

The Liberty field is proposed for development, but not yet producing. The Liberty field is located on federal leases approximately 5 miles offshore in the Beaufort Sea, southeast of the Endicott field. BPX owns the lease and estimates there are 120 million bbl of recoverable oil. BPX plans to develop Liberty using extended reach drilling from the Endicott Satellite Drilling Island. Production probably will begin in 2011 (Bailey 2008). ENI Corporation recently announced it has slowed work on the Nikaitchuq field, in the Beaufort Sea north and west of the Milne Point oilfield. The field has an estimated 180 million bbl of recoverable oil and production was anticipated to begin by 2009 but may now be delayed by lower oil prices and the global economy – for six months to a year (Lidji 2009).

Another potential development includes Sourdough. In 1997, BPX and Chevron announced the discovery of the Sourdough field next to ANWR. Current information indicates Sourdough could contain 100 million bbl of recoverable oil. Further exploration is needed before determining whether to develop the field. The Sourdough project would require up to 35 miles of pipeline to link up with the Badami field to the west (Staff 1997).

Table 6.2. North Slope and Beaufort Sea oil and gas accumulations.

Unit or Area	Oil Reserves (MMBO)[1]	Gas Reserves (Bcf)[1]	Royalty Percent	Royalty Oil Reserves (MMBO)	Royalty Gas Reserves (Bcf)
Badami Unit[2]	2	0	14.6%	0	-
Barrow					
East Barrow	-	5	0.0%	-	-
South Barrow	-	4	0.0%	-	-
Walakpa	-	25	0.0%	-	-
TOTAL Barrow	-	34		-	-
Colville River Unit					
Alpine	252	-	9.85%	25	-
CRU Satellite	203	-	14.2%[3]	33	-
TOTAL CRU	455	400		57	60
Duck Island Unit	120	843	12.5-14.4%	15	121
Kuparuk River Unit					
Kuparuk	799	1,000	12.5%	100	125
West Sak[4]	403	100	12.5%	50	13
Tabasco	8	-	12.5%	1	-
Tarn	41	50	12.5%	5	6
Meltwater	6	-	12.5%	1	
Other Kuparuk Satellite	-		12.5%	-	-
TOTAL KRU	1,256	1,150		157	144
Milne Point Unit[4]	331	14	14.6%	48	2
North Star	97	450	16.0%	16	72
Prudhoe Bay Unit					
Prudhoe IPA[5]	2,240	23,000	12.5%	280	2,875
PBU Satellites [4], [6]	504	-	12.5%	63	-
Aurora	43				
Borealis	117				
Orion	232				
Polaris	91				
Midnight Sun	15				
Greater Point McIntyre Area					
Lisburne	71	1,000	12.5%	9	125
Niakuk	15	26	12.5%	2	3
Pt. McIntyre	164	500	13.8%	23	69
TOTAL GPMA	250	1,526		33	197
TOTAL PBU	2,995	24,526		376	3,072
Point Thomson Area	295	8,000	12.5-16.0%	37	1,000
Other Undeveloped[7]	392	-	6%[8]	23	-
TOTAL North Slope (State Lands)	5,943	35,417		694	3,471
NPR-A	246				
TOTAL North Slope Alaska	6,189	35,417	-	694	3,471

1 Remaining recoverable oil reserves based on the sum of Alaska Department Revenue forecasted production from 2007 through 2036. Gas reserves estimates from DNR. MMBO = Million Barrels of Oil; Bcf = Billion Cubic Feet.

2 The Badami field was put in warm shut-in in August 2003; production resumed in 2005.

3 Average of royalty rates on State of Alaska lands.

4 Based on an aggressive heavy oil component.

5 Prudhoe Bay Initial Participating Area includes Prudhoe Oil Pool oil, gas, and gas liquids; Gas Cap gas; and gas injected to enhance oil recovery.

6 Includes Aurora, Borealis, Orion, Polaris, Midnight Sun, and Raven Pools.

7 Includes Liberty and other known offshore accumulations.

8 Estimated combined rate for State and Federal on- and off-shore accumulations.

As production of existing fields continues, production and development well drilling and well workovers will occur into the future. The extent of activity is likely to decline as fields become depleted. Several undeveloped accumulations (e.g. Sourdough, Point Thomson, Yukon Gold) are located beyond the existing pipeline infrastructure. These accumulations may or may not be developed. Existing fields also contain considerable amounts of gas that may be extracted and transported to market in the future. Tapping the North Slope's gas reserves may require additional facilities, wells, and a new pipeline.

3. Activity Subsequent to the Sale

It is reasonable to assume that some exploration drilling will 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 Beaufort Sea depend on several factors: 1) the subsurface geology of the area, 2) a company's worldwide exploration strategy, and 3) the projected price of oil and its demand. 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 can be assured an acceptable profit. This depends on the price of oil, the lessee's development costs, and the cost of getting the oil to market.

Where gas has been discovered, not more than one well per section (640 acres) 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.

When the development area is offshore and not within reach of existing infrastructure, a new platform, or drilling island may be proposed. Existing offshore platforms and structures were constructed onshore, floated to the desired location, sunk, and driven in place. A platform consists of a steel jacket with legs fastened to the seabed and the topside, which houses the staff and equipment necessary for producing oil and gas. Each leg is fastened to the seafloor with piles that penetrate about 135 feet below the surface. The piles serve as drilling slots and conductor pipe. Offshore drilling units that may be used during the production phase include:

- Rigid platforms
  - Steel-jacket platform (piles; >1,000 feet water)
  - Concrete gravity platforms
  - Steel-caisson platform (tide and ice resistant)
- Compliant platforms (moves with wind, currents and waves)
  - Guyed-tower platforms (guy wires, clump weights)
  - Tension-leg platforms (steel tubes to bottom, tensioned by buoyancy).
- Islands
  - Man-made.
  - Natural barrier islands.

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 feet. A separation facility removes water and gas from the produced crude, and pipelines carry the crude to the onshore storage and terminal facilities. Some of the natural gas produced is used to power equipment on the platform, well pad, or processing facility but most is re-injected 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.

Oil and gas production facilities found on the topside of a platform 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 that can move between legs, housing for about 75 workers, and a helipad. Island facilities would have a similar array of equipment, structures, and housing similar to platforms. Onshore support facilities include a production facility to receive and treat or transport the oil and gas to markets, refineries, or for trans-shipment to other processing facilities in the lower 48 states. Other support facilities may include a supply base and vessels to provide the platform with cement, mud, water, food, and other necessary items, and a helicopter base. Islands used for development would have a similar supply base and would use ice roads, barges, and helicopters, similar to platforms.

Onshore and offshore 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.
- 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.

Onshore and offshore oil production steps are:

- Produced crude oil goes through a separator to remove water and gas from the oil stream.
- The oil moves to an onshore 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.

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. Oil and Gas Infrastructure on the North Slope/Beaufort Sea

The North Slope hosts an extensive network of petroleum production, development, and support facilities, all leading to the TAPS gathering facility, into the pipeline, and, ultimately, the TAPS terminal in Valdez. Prudhoe Bay continues to function as the hub of activity for the 35 fields and satellites on the Slope and in the Beaufort Sea, extending outward via roads, pipelines, production and processing facilities, gravel mines, and docks. Deadhorse houses an industry-support community and airport. Thus far, all oil and gas facilities are onshore or in state waters, with none sited in the OCS.

As exploration and development have continued, oil companies – and regulatory agencies – have capitalized on technological advances and existing infrastructure, thus minimizing further environmental impacts. For example, The Liberty field is located in federal OCS waters approximately 5 miles offshore in the Beaufort Sea, southeast of the Endicott field. BPX plans to develop Liberty using extended reach drilling from the Endicott Satellite Drilling Island, thus eliminating the need for building a new gravel island or causeway or siting an offshore drill rig.

5. Oil and Gas Lease Sales on the North Slope, and Beaufort and Chukchi Seas

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 North Slope lease sale (Sale 13) in December 1964, the state has held 56 oil and gas lease sales involving North Slope and Beaufort Sea acreage (Table 6.3). More than 11.5 million acres in 3,065 tracts have been leased (Table 6.4). Some of this acreage has been leased more than once, as leases expired or were relinquished. Historically, only about half of the tracts offered in state oil and gas lease sales have been leased. Of the leased tracts, 407 (about 13 percent) were drilled and only 292 tracts, or about 10 percent of those leased, have been commercially developed. From 1944 through 2008, 506 exploration wells were drilled on the North Slope. During this period, the number of exploration wells drilled annually has ranged from 0-35. From 2004 through 2008, in a time of climbing oil prices, the number of exploration wells drilled annually has ranged from 9-15, averaging 12 per year and within historical ranges.

MMS has held 10 lease sales in the Alaska OCS over 30 years. A February 2008 lease sale in the Chukchi Sea attracted a record setting $3.4 billion in bids. High bids added up to nearly $2.7 billion on 2.76 million acres, with Shell Oil and ConocoPhillips showing the most interest (Joling 2008).

MMS is considering holding sales in federal OCS waters of the Beaufort Sea in 2009 and 2011, as well as the Chukchi Sea in 2010 and 2012 (MMS 2008, Vol. I). As of November 1, 2008 there were 281 active leases on federal submerged lands in the Beaufort Sea (MMS 2008, Vol. I, Chapter Three).

Table 6.3. Summary of state competitive lease sales on the North Slope/Beaufort Sea.

Date	Sale Number	Sale Name and Description
12/9/1964	13	Prudhoe West; offshore/uplands
7/14/1965	14	Prudhoe West to Canning R.; offshore/uplands
1/24/1967	18	Katalla, Prudhoe; offshore/uplands
9/10/1969	23	Colville to Canning R.; offshore/uplands
12/12/1979	30	Beaufort Sea (joint federal & state sale): offshore Milne Pt. east to Flaxman Is.
9/16/1980	31	Prudhoe Uplands: Kuparuk R. to Mikkelsen Bay
5/26/1982	36	Beaufort Sea: Pt. Thomson area; offshore/uplands
9/28/1982	34	Prudhoe Uplands: Sagavanirktok R. to Canning R.
5/17/1983	39	Beaufort Sea: Gwydyr Bay to Harrison Bay; offshore/uplands
5/22/1984	43	Beaufort Sea: Pitt Point east to Harrison Bay; offshore
5/22/1984	43A	Colville R. Delta/Prudhoe Bay Uplands Exempt: West of Kavik R.; offshore/uplands
9/24/1985	45A	North Slope Exempt: Canning R. to Colville R.; offshore/uplands
9/24/1985	47	Kuparuk Uplands: South of Prudhoe Bay
2/25/1986	48	Kuparuk Uplands: South of Kuparuk oil field
2/25/1986	48A	Mikkelsen Exempt: Mikkelsen Bay, Foggy Is. Bay; offshore/uplands
1/27/1987	51	Prudhoe Bay Uplands: Canning R. to Sagavanirktok R.
6/30/1987	50	Camden Bay: Flaxman Is. to Hulahula R.; offshore
9/28/1988	55	Demarcation Point: Canning R. to U.S./Canadian border; offshore
9/28/1988	69A	Kuparuk Uplands Exempt: Canning R. to Colville R.
1/26/1988	54	Kuparuk Uplands: Colville River Delta
1/24/1989	52	Beaufort Sea: Pitt Point to Tangent Point; offshore
1/24/1989	72A	Oliktok Point Exempt: Uplands
1/29/1991	70A	Kuparuk Uplands Exempt: Canning R. to Colville R.

-continued-

Table 6.3. Page 2 of 2.

Date	Sale Number	Sale Name and Description
6/4/1991	64	Kavik: Canning R. to Sagavanirktok R.; uplands
6/4/1991	65	Beaufort Sea: Pitt Point to Canning R.; offshore
1/22/1992	61	White Hills: Colville R. to White Hills; uplands
6/2/1992	68	Beaufort Sea: Nulavik to Tangent Point; offshore
12/8/1992	75	Kuparuk Uplands: Between NPRA and Sagavanirktok R.; Colville R. Delta ASRC Islands
5/25/1993	70A-W	Kuparuk Uplands Reoffer: Between Canning R. and Kavik R.; onshore
9/21/1993	75A	Colville River Exempt: Colville River Delta onshore
12/5/1995	80	Shaviovik: Sag R. to Canning R., southern Kuparuk Uplands, Gwydyr Bay, Foggy Island Bay, onshore/offshore
10/1/1996	86A	Colville River Exempt: Colville R, offshore, state/ASRC onshore/offshore
11/18/1997	86	Central Beaufort Sea: Harrison Bay to Flaxman Island
6/24/1998	87	North Slope Areawide: state acreage between NPRA and ANWR north of the Umiat Baseline
2/24/1999		North Slope Areawide 1999 state acreage between NPRA and ANWR north of the Umiat Baseline
11/15/2000		North Slope Areawide 2000 state acreage between NPRA and ANWR north of the Umiat Baseline
11/15/2000		Beaufort Sea Areawide 2000 state acreage within the 3-mile limit, between Dease Inlet and Barter Island
10/24/2001		North Slope Areawide 2001 state acreage between NPRA and ANWR north of the Umiat Baseline
10/24/2001		Beaufort Sea Areawide 2001 state acreage within the 3-mile limit, between Dease Inlet and Barter Island
10/24/2002		North Slope Areawide 2002 state acreage between NPRA and ANWR north of the Umiat Baseline
10/24/2002		Beaufort Sea Areawide 2002 state acreage within the 3-mile limit, between Dease Inlet and Barter Island
10/29/2003		North Slope Areawide 2003 state acreage between NPRA and ANWR north of the Umiat Baseline
10/29/2003		Beaufort Sea Areawide 2003 state acreage within the 3-mile limit, between Dease Inlet and Barter Island
10/27/2004		North Slope Areawide 2004 state acreage between NPRA and ANWR north of the Umiat Baseline
10/27/2004		Beaufort Sea Areawide 2004 state acreage within the 3-mile limit, between Dease Inlet and Barter Island
3/1/2006		North Slope Areawide 2006 state acreage between NPRA and ANWR north of the Umiat Baseline
3/1/2006		Beaufort Sea Areawide 2006 state acreage within the 3-mile limit, between Dease Inlet and Barter Island
10/25/2006		North Slope Areawide 2006A state acreage between NPRA and ANWR north of the Umiat Baseline
10/25/2006		Beaufort Sea Areawide 2006A state acreage within the 3-mile limit, between Dease Inlet and Barter Island
10/24/2007		North Slope Areawide 2007 state acreage between NPRA and ANWR north of the Umiat Baseline
10/24/2007		Beaufort Sea Areawide 2007 state acreage within the 3-mile limit, between Dease Inlet and Barter Island
10/22/2008		North Slope Areawide 2007 state acreage between NPRA and ANWR north of the Umiat Baseline
10/22/2008		Beaufort Sea Areawide 2007 state acreage within the 3-mile limit, between Dease Inlet and Barter Island

Table 6.4. Current lease activity, North Slope and Beaufort Sea.

Lease Sale Areas	Number of Leases	On-Shore Acreage	Off-Shore Acreage	Total Acreage
North Slope	716	2,100,853.78	82,510.99	2,183,364.77
Beaufort Sea	224	53,337.09	561,940.34	615,277.43
Active Leases	940	2,154,190.87	644,451.33	2,798,642.20

BLM has leased onshore federal lands as well, in NPRA. The most recent sale was held in September 2008 and leased 150 of the 450 tracts offered (BLM 2008a). These 1,656,754 acres add to the 335 existing NPRA leases, totaling 3,086,492 acres (BLM 2008a*).* Oil and gas is also estimated to occur in the Arctic National Wildlife Refuge and the Teshekpuk Lake area of NPRA. ANWR is closed to development and BLM has deferred for 10 years the potential leasing of lands north and east of Teshekpuk Lake, from the lake to the coast (BLM 2008d).

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 question of how best to transport oil or gas discovered in offshore areas of Alaska's northern coast has been studied for many years. Numerous options have been identified and periodically updated to incorporate technological improvements. The method for bringing offshore oil to shore that is generally most favored by the U.S. Army Corps of Engineers is through directional drilling from onshore locations. There are, however, limits to directional drilling. Factors such as the location of the oil deposit in relation to the drilling rig, the size and depth of the deposit, and most importantly, the geology of the area are all critical elements in determining if directional drilling is feasible (see Appendix C).

If directional drilling is not feasible, oil produced from offshore tracts in the Beaufort Sea could be brought onshore by a number of methods that are discussed below. However, the economic feasibility of development cannot be precisely addressed at the lease sale stage because the existence, location, and extent of any future discovery are not known before exploration. Ultimately, strategies used to transport potential petroleum resources depend on many factors, most of which are unique to an individual discovery. The location and nature of oil or gas deposits determine the type and extent of facilities necessary to develop and transport the resource. ADNR and other state, federal, and local agencies will review the specific transportation system when it is actually proposed. Modern oil and gas transportation systems usually include the following major components: pipelines, marine terminals, and tank vessels. Shallow waters in the lease sale area will likely preclude the use of marine terminals or tankers to transport oil. 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.

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

The mode of transport from a discovery will be an important factor in determining whether future discoveries can be economically produced – the more expensive a given transportation option is, the larger a discovery will have to be in order to be economically viable.

Portions of the lease sale area lie offshore of ANWR and NPR-A. While 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, upland from the lease sale area. 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 analysis is based on the assumption that ANWR will not be available for onshore support of a transportation system.

DO&G

Pipeline crossing the Kuparuk River.

1. Pipelines

A pipeline is considered all the components of a total system of pipe to transport crude oil or natural gas or hydrocarbon products for delivery, storage, or further transportation. It includes all pipe, pump or compressor stations, station equipment, tanks, valves, access roads, bridges, airfields, terminals and terminal facilities, operations control center for both the upstream part of the and all other facilities used or necessary for an integral line of pipe transportation (AS 38.35.230).

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) and specific 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, 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 program is to assure pipeline operators have systematic, rigorous, and documented processes in place to protect HCAs. (PHMSA 2008).

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.
- For liquid hydrocarbon (oil and product) pipelines, Pipeline Integrity Management in High Consequence Areas 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 High Consequence Areas (HCAs) within the United States. These HCAs include population areas (like Nuiqsut and Deadhorse), drinking water and ecological resources that are unusually sensitive to environmental damage, and commercially navigable waterways.

a. <u>Offshore Pipelines</u>

i. Subsea Pipelines

Subsea pipelines are the most likely system for transporting oil or gas from new offshore development areas to loading or processing facilities. The Beaufort Sea’s first subsea pipeline carries oil 6 miles offshore from Northstar to onshore pipe in Prudhoe Bay. The Oooguruk development also uses a subsea pipeline to carry oil from a gravel island 5 miles offshore in 5 feet of water. Offshore pipelines that are properly designed and maintained do not hinder water circulation and minimally affect fish and wildlife habitat. If offshore pipelines are not buried, they can hinder or disrupt normal water circulation. Pipelines may be buried in trenches in shallower waters, as was done at Oooguruk, to avoid creating a navigational hazard, being damaged by a ship's anchor or sea ice, or being caught in fishing nets. In deeper water, the pipelines may become silted-in or self-buried. The risk of spills from subsea pipelines is considerably less than for tankers (MMS 1992). However, subsea pipelines are expensive to build and maintain. Although significant advances have been made in recent years, they can also be difficult to monitor for leaks, defects, and corrosion problems. See Section F(2)(a) below for further information on leak detection methods.

Although much more expensive than an onshore pipeline across a portion of the ANWR Coastal Plain or through NPR-A, a main offshore pipeline that completely avoids ANWR and NPRA can be constructed to transport oil from leases offshore from these areas. A careful analysis of the economics and environmental risks would have to be performed to determine which transportation method would be best. This can only be done after a discovery is made and evaluated.

One method of subsea pipeline construction involves winter excavation of a trench in the sea bottom using a plow, dredge, jetting action, or a shovel-type device. The trench could be cut using a plow, dredge, jetting action, or shovel type device, depending on water depths and soil characteristics. The depth of the trench is dictated by the depth of the water, local soil conditions, equipment limitations, and projected hazards expected over the life of the pipeline. Pipe is then laid in the trench, and the trench is back-filled.

In the Beaufort Sea, subsea pipelines come ashore at the nearest suitable approved landfall and pass through the nearshore permafrost transition zone inside of or on top of short causeways, through directionally drilled tunnels, or in insulated pipes bedded in gravel-filled trenches. Of the various options for bringing an offshore pipeline through the nearshore permafrost transition zone, installing the pipeline in a dredged trench appears to be the most suitable method, based on current technology. Other methods, such as the use of a causeway, may also be appropriate depending on the length of the shore approach zone, oil temperatures, and the permafrost sensitivity of the local soils (Brown 1984).

A major design consideration for both deep and shallow subsea pipelines in the Arctic Ocean is the risk of damage due to ice and strudel scouring. The ice scour process begins when a floating ice mass with a deep keel is driven against the ocean bottom. These ice masses are driven by environmental forces, including winds, ocean currents, waves, or moving pack ice. Ice scour may not only directly damage pipe, but may damage subsea pipe by causing large shear strain in the soil (Schoonbeek et al. 2006). Once scouring begins, it will continue until soil or seabed resistance exceeds the strength of the ice keel or the forces pushing the ice (Been et al. 1990). Subsea pipelines will also experience external loading forces due to ice piling up on the sea floor above the pipeline. The extent to which ice can accumulate on the sea floor above the pipeline will depend on water depth, seasonal weather conditions, and local sea floor conditions. Consequently, where this potential exists, pipelines must be designed to accommodate this additional external force. New computer modeling techniques that analyze extreme seabed deformation undergoing ice gouging may facilitate engineering and environmental considerations of burying pipe (Offshore 2008). MMS has completed a study on seabed scour and pipeline deformation; the final report, which includes recommendations regarding the minimum required burial depth to protect pipe from ice scour, is under preparation (Kinnas et al. 2008b).

Strudel scour occurs when melting snow and ice on land flow over sea ice as the water is discharged from the river deltas. This fresh water over-flooding can extend several miles seaward from the river deltas and typically occurs in late May to early June. The weight of the fresh water depresses the sea ice where the ice is not bottom fast and causes the ice to crack. The fresh water drains through these cracks. If sufficient static head of fresh water exists, the water drains through the cracks/holes with enough velocity to form a whirlpool waterjet that can scour the seafloor. Individual strudels can vary in size and are typically circular in shape. Strudel scour depths and diameters vary depending on location. In the vicinity of the Northstar pipeline right-of-way, they reach depths up to 13 feet below the seabed and diameters vary in size from a few feet up to 89 feet measured at seabed elevation. Northstar pipelines where this potential exists must have adequate strength to span the potential strudel scour conditions in the area (SPCO 1999).

Subsea pipelines in the Beaufort Sea must also be designed to withstand earthquakes. Both TAPS and subsea pipelines in the area have been designed to avoid damage from earthquakes. For more on geophysical hazards, see Section A of this Chapter and Section F of Chapter Three.

Subsea pipelines are expensive to construct and maintain. A hot oil pipeline buried through the nearshore permafrost transition zone must be designed for upheaval, bucking, and thaw settlement. It could also be subject to damage during conditions of severe ice scouring. If a subsea pipeline rupture were to result in an oil spill, detection, containment, and cleanup would be more difficult than if the pipeline was on a causeway above the surface of the water or ice. Moreover, maintenance and repair costs for a subsea pipeline are high, as access to the pipeline route maybe limited to winter ice roads or barges during the open water period.

Potential nearshore impacts from subsea pipelines can also be significant. Construction of a pipeline in shallow water and through shoreline areas involves dredging, canal building, or construction of a short causeway out to a deeper water area. These operations have the potential to alter the environment. Although pipeline burial is normally desirable, it is more difficult with certain types of sediment. For example, if the pipeline traverses frozen sediment and the pipeline is not properly insulated, heat transfer from the pipe could result in slumping or the creation of mobile slurries (Baker 1987). Pipeline burial, inspection, and maintenance operations can also create significant noise disturbance and changes in water quality that may adversely affect marine mammals. However, there is no evidence of population changes in those species that can be attributed to the much higher and more persistent levels of industrial noise from similar activities in the Canadian Beaufort Sea (USACOE 1984). Dredging and pipe laying activities may also disturb birds, but to a lesser extent and for a shorter duration than under the causeway alternatives (USACOE 1984).

Although TAPS is an onshore pipeline, the construction and operation of the TAPS line has provided valuable information on the construction of pipelines in permafrost areas and in the choice of materials to use in arctic conditions. Similarly, the construction of buried pipelines in the now-producing fields on the North Slope has also provided valuable construction and design parameters that can be used in the design of offshore Arctic pipelines.

Subsea pipelines have been successfully constructed using current technology in both shallow and deep water areas around the world. The unique conditions present in the Arctic present engineering challenges. Site specific and project specific ice studies, ice loading studies, soil condition analyses, permafrost studies, water current and wave studies, ice and strudel scour studies, external and internal pipeline stress studies, and corrosion control studies will have to be completed in order to design and construct a subsea pipeline.

For the Northstar development project, BPX built a 6-mile subsea pipeline from Seal Island to landfall. A slot was cut in the ice along the subsea pipeline route and a trench was excavated in the seafloor for pipeline installation. The trench walls are approximately vertical in the area of landfast ice and trapezoidal in floating ice areas. Trench depth ranges from 7 to 12 feet. The bottom of the trench was cut to the desired final grade by use of a hydraulic excavator, which discharged the excavated material back into the trench. Tracked equipment towed pipeline strings to the side of the trench where they will be welded together and lowered through the opening into the seafloor trench. The pipeline was coated with fusion-bonded epoxy to protect against exterior wall pipeline corrosion. In addition, a cathodic protection system consisting of anodes attached to the pipelines helps prevent corrosion. (USACOE 1999). BPX estimated the maximum depth of ice scour to be 2 feet along the pipeline route. To help prevent thawing of the permafrost, oil is cooled to a temperature of 50˚ F (from 175˚ F) before being sent through the pipeline (Gipson Undated).

ii. Elevated Pipeline

Elevated pipelines are essentially a series of 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. 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 in the seabed. However, none have been built in the Beaufort Sea.

Several difficulties accompany the use of elevated pipelines in the Beaufort Sea. Access to the pipeline for maintenance and repairs may be difficult during storms, surges, and broken ice conditions in the fall and spring. The pipeline will need to be elevated off the surface of the water because of the potential for ice or wave damage. This significantly adds to the cost of constructing the pipeline and complicates access for maintenance and repairs. In the nearshore permafrost transition zone, the pilings could be subject to jacking and subsidence, both of which could threaten the integrity of the pipeline. Pilings will also be subject to increased stress resulting from ice collisions and ice sheer in deep water areas. A pile-supported pipeline could lead to higher marine noise levels than other transportation alternatives because noise will be conducted into the water through the steel structures supporting the pipeline. However, the effects of pipeline-created noise disturbance on marine mammals will be negligible because of the shallow water depths in the lease sale area (noise propagates poorly in shallow water) and because marine mammals generally inhabit deeper waters farther from shore (USACOE 1984). Finally, depending on its location, an elevated pipeline could create a significant navigational hazard.

iii. Gravel Causeway

A proven method, gravel causeways are generally cost effective. However, because of the high cost of transporting gravel to these remote Beaufort Sea areas, even this relatively low cost type of structure can be prohibitively expensive for the development of marginal fields far offshore (i.e., fields with relatively small reserves, high development costs or a combination of the two) or in deeper waters. As water depths increase, the amount of gravel required to construct a causeway increases significantly. For example, a given length causeway in 15 feet of water requires almost 10 times as much gravel as the same structure in 5 feet of water. Consequently, the feasibility of using gravel in progressively deeper waters depends on the size of the oil reserve.

Transporting oil by means of a continuous solid fill gravel causeway in nearshore areas has several advantages. Pipelines used for transporting oil may be buried in or placed on top of a causeway to facilitate visual inspection and provide a stable operations and logistics base for containing and cleaning up any spills that may occur. Solid gravel causeways can also support the heaviest loads on a year-round basis and provide the additional benefit of year-round access to offshore production facilities. Moreover, causeways, like the one at West Dock, are capable of serving as loading and off-loading points for barges bringing fuel, supplies, and equipment into the exploration and production area. They may also be used as corridors for pipelines bringing seawater ashore for reinjection into the ground to maintain onshore oil field pressures.

Although a causeway can cause changes in water circulation patterns affecting temperature and salinity, it is not expected that the deeper water food sources eaten by ringed seals and whales would be affected by these changes (USACOE 1984). Based upon experiences with causeways at West Dock and Endicott, proper siting of causeways can minimize the risk of important habitat loss.

Longer nearshore causeways are considered by some to be environmentally unacceptable because of their potential to alter tidal and nearshore currents, water exchanges, water salinity and temperature. It is feared that alterations of this nature could have significant and long term effects on fishery resources. Depending on where they are sited, causeways, if not properly marked and maintained, can also present a navigational hazard or obstacle where none previously existed. For more on effects of causeways on fish, birds, and marine mammals, see Chapter Eight.

The state of Alaska discourages the use of continuous fill causeways. Environmentally preferred alternatives for field development include use of buried pipelines, onshore directional drilling, or elevated structures. If approved, causeways must be designed, sited, and constructed to protect water quality, nearshore fish passage, and nearshore oceanographic circulation patterns.

The construction of continuous fill causeways can have adverse environmental effects depending on the length, orientation, and the specific location of the structure. Disturbance of marine mammals and birds may occur during the construction phase because of noise (USACOE 1984; Dames and Moore 1988). Placement of gravel in nearshore waters may also result in temporary turbidity plumes (USACOE 1984) that can affect marine organisms and their habitat. When ice flexes and rides up on a causeway the resultant breaks in the ice may provide an entry point for water and promote strudel scour. Solid-fill causeways may also have an adverse effect on marine and anadromous fish passage, and can alter primary (plankton) production regimes in nearshore estuarine habitat. However, proper siting of causeways can minimize the risk of habitat loss. Although the post-construction environmental effects of continuous solid fill causeways are the subject of differing opinions, it is generally accepted that nearshore causeways have little or no effect on marine mammals. Bowhead and gray whales are occasionally sighted in nearshore areas of the arctic coast but they normally inhabit deeper water further from the shore. The noise level from a causeway is also relatively low, and noise propagates poorly in shallow waters where causeways would normally be constructed.

A breached causeway is essentially the same type of structure as described above except that the gravel fill is interrupted by one or more openings of varying length to allow for greater ocean water circulation and fish movement. The Endicott and West Dock causeways are examples of this type of design and construction. Although numerous studies have been initiated to determine the environmental impacts of each of these existing structures, there is little consensus concerning the findings. Studies of fish, marine mammals, and sea birds have produced findings from different reviewers ranging from little or no impact to significant habitat degradation or alteration. Studies concerning water quality have also varied in their findings. However, it is generally accepted that during certain periods of the open water season, there are transient changes in nearshore water temperature and salinity. Whether there are adverse environmental impacts resulting from the observed changes remains the subject of controversy.

Breaching a causeway minimizes disruption of water circulation patterns and any resulting changes in water quality that may occur. Detailed studies are available concerning the breached causeways for the West Dock and Endicott projects. In shallower waters, culverts may be used to form the breach, thus reducing overall costs.

Although breaching a causeway reduces the risks of environmental harm from disruption of water circulation patterns, it has certain disadvantages. For example, in comparison to unbreached causeways, breached causeways have higher construction and maintenance costs. The superstructure across the breach, unless the breach is formed by culverts, cannot support unrestricted loads. This could pose safety problems in the event of a well blowout or oil spill, which might require rapid movement of very heavy equipment to or from the scene.

iv. Elevated Causeway

This transportation alternative is similar to an elevated pipeline, but would include an accompanying road surface built on the pipeline supports. The road surface would allow for easier year-round maintenance, inspection, and access to offshore production sites serviced by the structure; but the initial costs associated with construction of the roadway would be substantial.

Like the elevated pipeline alternative discussed above, this option provides for uninterrupted water circulation and improved visual monitoring of the pipeline for leaks. The bridge roadway could also be designed to provide limited containment of small spills on the causeway, and all but the heaviest types of equipment could be transported between shore and production islands on a year-round basis.

The difficulties with the use of an elevated causeway are similar to those discussed above with regard to elevated pipelines, and none have been constructed in the Beaufort Sea. Although access to the pipeline for routine maintenance is improved by the presence of the road surface, access to the supporting superstructure for major repairs may be complicated by broken ice conditions in the fall and spring. The causeway would require the same elevation standard as an elevated pipeline, because of the potential for ice or wave damage. This would substantially add to the cost of constructing the causeway.

Elevated causeways share the same concerns as elevated pipelines. These are the risks of jacking-up and subsidence of the pilings supporting the causeway and increased stress on the pilings caused by ice collisions and ice shear. It is also possible that a pile-supported causeway could lead to higher marine noise levels by conducting noise into the water through the steel structures supporting the road and pipeline. More importantly, noise from traffic on the road could enter the water beneath the bridge. Thus, airborne noise could now enter the water directly, rather than be absorbed by the gravel causeway (USACOE 1984). As with elevated pipelines, however, the effects on marine mammals are expected to be negligible because the water depths where the structure would be located in the lease sale area are extremely shallow and the marine mammals tend to inhabit deep water farther from shore. This type of causeway cannot support unrestricted loads. Access restrictions (weight and size limitations) would limit the loads that could be safely transported over the causeway. Like other causeway alternatives, an elevated causeway could present a navigational hazard.

Construction and maintenance costs are high for this option. During the construction phase, disturbance of birds may occur if pile-driving or other construction work on or near the shore occurs during the summer. Construction of an elevated pipeline would also result in temporary turbidity plumes (USACOE 1984: 4-184). For its Alpine development project, ARCO constructed an oil pipeline under the Colville River. The Colville River pipeline is designed for a minimum service life of 20 years. The pipeline was installed at a depth of approximately 80 ft or greater beneath the river bed using horizontal directional drilling methods (Parametrix 1996). The pipeline is insulated and is operated such that the oil temperature will ensure that thaw settlement will be within tolerable limits. The leak detection system employs real-time monitoring supplemented by the use of inspection pigs.

2. Tankers

Tankers are currently used in Alaska to transport oil to and from Cook Inlet and from the Alyeska Terminal in Valdez, the terminus of TAPS. Use of tankers brings the risk of a large oil spill, such as the 1989 *Exxon Valdez* spill in Prince William Sound (see Section F below). Shallow waters in the lease sale area mean nearshore tanker traffic is not a viable option.

3. Mitigation Measures and Other Regulatory Protections

Any product ultimately produced from lease sale tracts 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. Measures are included in this final 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 if exploration and development take place.

F. Oil Spill Risk, Prevention, and Response

The risk of a spill exists any time crude oil or petroleum products are handled.

1. Oil Spill History and Risk

The National Research Council (MMS 2008, Vol. I, Chapter Three) reports that accidental discharges into the sea from exploration and production account for 2 percent of the total release of petroleum spilled into North American seas. Oil consumption accounts for 32 percent and marine transportation 3 percent. The largest source of oil in the sea is natural seeps (63 percent of total inputs).

The nine largest spills of crude oil and process water in the North Slope Subarea, those over 1,000 bbl (42,000 gal), are listed in Table 6.5; these are the largest spills in the Subarea since 1995. Since July 1995, there has been one spill involving over 1,000 bbl of crude oil; the other spills involved produced water or seawater. Since 1995, there have been 80 spills of crude oil and process water over 23.81 bbl (1,000 gal) in the North Slope subarea. Most spills are much smaller; about 85 percent of crude spills (since 1995) (ADEC 2009) are less than 2.381 bbl (100 gal) and about 55 percent of process waters spills are less than 2.381 bbl (100 gal). The smallest recorded crude spill in ADEC's spill database is .063 gallons spilled in May 1997 when equipment at Pump Station 2 failed (Stephens 2009). Process water – seawater and produced water, the water pumped with oil and gas from wells – may contain crude oil; hence, these spills are included here.

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 3 decades. In this time, the vast majority of oil, produced fluid, seawater, and other industry-related spills have been less than 0.238 bbl (10 gal), with very few larger than 10,000 bbl (42,000 gal) (see Table 6.5). MMS estimates the mean number of a large, 1,000 bbl (42,000 gal) spill in its preparation for its proposed Beaufort Sea sales as small: the estimated mean number of spills over the life of production is less than one (.30 or one third of a spill) (MMS 2008, Vol. I, Chapter Four). 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 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).

Table 6.5. Large spills (over 1,000 barrels) of crude oil or process water in the North Slope subarea, July 1995 to January 2009.

Date	Location	Facility Type	Substance	Gallons Released	Barrels Released
3/17/97	Drill Site 14	Oil Production Onshore	Seawater	995,400	23,700
3/2/06	Flowline between GC1 and GC2	Oil Production Crude Oil Transmission Line	Crude	267,000	6,357
12/19/06	Gathering Center 2 (GC-2)	Oil Production Field Processing	Produced Water/Crude (Crude 6,300 gal; 150 bbl)	241,038	5,739
12/25/08	1 L Pad Well 22	Oil Production Flow Lines	Produced Water	94,920	2,260
4/15/01	Kuparuk, from CPF1 to Drill Site 1B	Oil Production Field Processing	Produced Water	92,400	2,200
1/10/98	Kuparuk, ARCO DS 1A	Oil Production	Produced Water	63,000	1,500
11/3/08	Drill Site 11	Oil Production Onshore	Seawater	61,626	1,467
3/26/05	Drill Site 2-H	Oil Production Field Processing	Produced Water	51,198	1,219
6/16/08	Skid 50	Oil Production Onshore	Source Water	49,387	1,176

Source: Adapted from Stephens 2009.

2. 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; offshore gravel islands or causeways; drill rigs; pipelines; and facilities for gathering, processing, storing, and moving oil. 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.

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, 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.

Blowouts are extremely rare in Alaska and their numbers decline as technology, experience, and regulation impact drilling practices (ADN 2008). A blowout that results in an oil spill has never occurred in Alaska. Natural gas blowouts have occurred, About 5,570 wells have been drilled on the North Slope; it’s been over 13 years since the last gas blowout (ADN 2008). Since 1976, there have been six documented instances of loss of secondary well control with a drill rig on the well. This equates to 1.8 blowouts per 1000 wells (Mallary 1998). 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 plugs the well (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 killed 3 days later by pumping heavily weighted drilling muds into it (Schmidt 1994; ADN 1994a).

The largest spill in the region is the March 1997 spill of almost a million gallons of process water (seawater) that seeped from nine wellheads at Drill Site 9 (Meggert 2009; ADEC 2009). The water was channeled directly into an old reserve pit and frozen in place. It was chipped up, melted, and re-injected at another water flood injection well. Seawater spills that reach tundra are significant because salty water can kill vegetation.

The most recent spill of produced water and crude occurred on January 12, 2009 at Milne Point’s Central Facilities Pad. A sand slurry tank and secondary containment overflowed when the automated flow control system failed, spilling an estimated 575 bbl (24,150 gal) of crude and produced water (ADEC 2009). An electronic component of the tank’s automatic flow control system failed, releasing oil and produced water into the containment basin and onto the gravel pad (Bluemink 2009b).

a. 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; and DEC. Federal agencies include the Pipeline and Hazardous Materials Safety Administration (PHMSA) within the U.S. Department of Transportation; and 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, most recently, December of 2008, have made the oil and gas industry, local, state, and federal regulators, and the public acutely 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 history (ADEC 2009; ADN 2006a). The cause of the leak was internal microbiological corrosion the pipeline (Bailey 2006). A one-quarter inch hole formed in the bottom of the pipeline in a section than had been buried under a caribou crossing. The snow covered the leak, causing delayed detection; ultimately, the odor exposed the leak to a worker. An ADEC report issued in April 2006 stated that spill alarms went off for 4 consecutive days in late February; however, the alarms were dismissed by operators monitoring the system as false (ADN 2006a). 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 (Loy 2006; ADN 2006a). BP Exploration Alaska, the Prudhoe Bay operator, had not pigged the pipeline that leaked to test for internal corrosion since 1998 (ADN 2006a).

Additionally, on March 9, 2006, spill responders found 12 bbl (500 gal) of oil 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 a response to the August 2006 shutdown, transit lines were pigged weekly and continuous corrosion inhibitor was added to the transit lines (Nelson 2007a). 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 of 2008 (Quinn 2009).

On December 19, 2006, 234,738 gallons of produced water and 150 bbl (6,300 gal) of crude were spilt at Gathering Center 2 (ADEC 2009). 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. All of the oil was recovered (ADEC 2009). One to 2 gallons of produced water flowed through a hole in the containment liner to the gravel pad.

On Christmas day of 2008, a corroded water injection pipe at Kuparuk released 2,260 bbl (94,920 gal) of produced water (ADEC 2009). The spill sprayed nearly 3 acres of tundra with a light misting of oily water and contaminated 2 acres of gravel at the well pad (Bluemink 2009a).

After the 2006 spills, addressing issues of corrosion and pipeline monitoring became a state priority. 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.

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

b. <u>Tankers</u>

Shallow nearshore waters prevent the use of tankers for transporting oil from the North Slope. However, Alaska’s most catastrophic spill is the March 1989 *Exxon Valdez* tanker spill, and no discussion of Alaska’s spill history is complete without its inclusion. The *Exxon Valdez* spill, the largest recorded in U.S. waters, spilled nearly 261,900 bbl. Oil from the *Exxon Valdez* 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 (Alaska Office of the Governor 1989). Effects of oil spills on fish and other wildlife are discussed in Chapter Eight.

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 percent 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.

The oil spills from the *Glacier Bay* and the *Exxon Valdez* were not effectively contained, and the effectiveness of the cleanup efforts remains the subject of controversy. In the case of the *Glacier Bay* oil spill in Cook Inlet, cleanup was hampered by tidal currents and confusion concerning who would respond to the spill. In the *Exxon Valdez* oil spill in Prince William Sound, the sheer size of the spill quickly overtaxed available cleanup resources at a time when response plans had not been kept current. Although not on the scale of the *Exxon Valdez* spill, the *Glacier Bay* spill focused attention on oil spill response and cleanup capabilities in Cook Inlet.

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 later in this Chapter.

c. Alaska Risk Assessment of Oil and Gas Infrastructure

In May 2007, the Alaska Risk Assessment (ARA) project was launched. The purpose of the 3-year, $5 million initiative is to evaluate Alaska's oil and gas infrastructure for its ability to operate safely for another generation. It is expected that oil and gas infrastructure on the North Slope and Cook Inlet, and the Trans-Alaska Pipeline, will be included (ADEC 2008).

The ARA will provide status of existing infrastructure, components, systems, and hazards. The likelihood and consequences of possible failures in Alaska's oil and gas infrastructure will be examined, and potential failures that could affect the reliability of the system or its ability to sustain production without unplanned interruptions, will identified and prioritized. Rankings will be based on consequences to state revenue, safety, and the environment. Mitigation measures will be recommended based on identified risks (ADEC 2008).

3. Oil Spill Prevention

A number of measures contribute to the prevention of oil spills during the exploration, development, production, and transportation of crude oil. 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. For example, changes in technology, experience, and regulation are attributed by the Alaska Oil and Gas Conservation Commission as reducing the number of blowouts in Alaska (ADN 2008).

Technical design of pipelines and other facilities reduces the chance of oil spills. As discussed in Chapter Three, Section F, 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 with 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 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

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 prevention (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 (BPX 1996).

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. 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 of the drilling mud to compensate for the increased pressure. BOP drills are performed routinely with all crews to ensure wells are shut-in quickly and properly. Rig foremen, tool pushers, drillers, derrick men and mud men all have certified training in well control that is renewed annually (BPX 1996).

If well control is lost and there is an uncontrolled flow of fluids at the surface, a well control plan is devised. The plan may include instituting additional surface control measures, igniting the blowout, or drilling a relief well. Regaining control at the surface is faster than drilling a relief well and has a high success rate. A blowout may bridge naturally due to the pressure drop across the formations. Under these conditions, reservoir formations flow to equalize pressure and the resulting bridging results in decreased flow at the surface. The exact mechanical surface control methods used depend on the individual situation. Operators may pump mud or cement down the well to kill it; replace failed equipment, remove part of the BOP stack and install a master valve; or divert the flow and install remotely-operated well control equipment (BPX 1996).

While operators consider mechanical surface control methods, they also begin planning to drill a relief well by assessing the situation and determining the location for the relief well. Additionally, logistical plans to move another drill rig to the site are necessary. Conditions may require the construction of an ice or gravel pad and road. 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. Arranging for and drilling a relief well could take from 10 to 15 weeks depending on weather, cause of the blowout, choice of surface location and depth of the well (BPX 1996).

b. Leak Detection

In warmer climates offshore pipeline leaks are often detected when workers spot an oil sheen on the water during routine flights to offshore platforms (MMS 2008, Vol. I, Chapter Four). The presence of ice in the Beaufort Sea makes this impractical for much of the year, requiring the use of technology to detect leaks quickly.

External pressure on pipe in deepwater applications may limit concern for subsea leaks; in most cases, seawater will flow into the pipe instead of oil leaking out (Scott and Barrufet 2003).

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 have been 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). This technology can minimize spills from both new and old pipelines (Yoon and Mensik 1988).

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 percent 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 (Alyeska Pipeline Service Company 1999).

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 gasses 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 gasses 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. LEOS is being used at Northstar (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. The Pipeline and Hazardous Materials Safety Administration has jurisdiction over cross-country 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.

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, Vol. I, Chapter Four). 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 (ARCO 1998).

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.

For the Northstar project, the pipeline is monitored on a continuous basis by the Supervisory Control and Data Acquisition (SCDA) system and operators are provided with real-time information on pipeline status. Both USDOT and MMS require SCDA for sub-sea pipelines. This system can detect changes in flow rate to 0.15 percent of daily flow volume. To obtain early warning of potential leak points, pipelines are checked periodically by inspection pigs. Visual surveys detect chronic leaks below the threshold of the SCADA system.

When initially proposed, the Liberty project included a 6.12 mile subsea pipeline from shore to an island site in 22 feet of water inside of Beaufort Sea barrier islands (including onshore pipe, the total length would have been 7.5 miles); the project has since been modified to drill from the Endicott Satellite Drilling Island. While the project will no longer feature a subsea pipeline, a study considering design alternatives for the project concluded that steel pipe-in-pipe designs have less risk of failure. The study found that spill risk was affected by water depth of the hazard, the failure mode (rupture, crack, pinhole), performance of the monitoring system, third-party activities, and operational failures. The study also considered hazards posed by ice gouging, strudel scour, permafrost thaw settlement, thermal loads leading to upheaval buckling, corrosion, operational failures, and third party incidents. It was presumed that Liberty would have been fitted with a pressure point analysis/mass balance line pack compensation monitoring system. PPA/MPLPC would detect a rupture or crack but not pinhole seepage – and confirm it within one minute. The operator would review the alarm, shutdown the pump, and isolate the line. Oil flow into the line would stop when Liberty's valves at shore and on the island were closed, which would have taken about 8.5 minutes. Oil would continue to leak until the crack or rupture is repaired and the line is purged of oil. The study found that steel pipe-in-pipe, with its secondary containment, posed less risk than other designs. The study also found that operational failures and third-party activities were the most significant hazards for all designs. Ice gouging frequency, subgouge soil displacement algorithms, strudel scour generation rates and size, corrosion, occurrence probabilities for thaw subsidence, and upheaval buckling were less sensitive risk parameters (Dinovitzer et al. 2004).

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 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 (BLM 2008c) reports 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 - and acknowledge the placement of a pipeline at depth beneath a river could make detection and cleanup of a spill in the buried segment difficult.

Autonomous Underwater Vehicles (AUVs) and Remotely Operated Vehicles (ROVs) offer new pipeline monitoring and spill response technology. AUVs and ROVs can carry out unmanned underwater investigations. AUVs can be equipped with video cameras and used to inspect subsea pipelines or survey the underside of ice to look for pooled oil. AUVs are currently limited to daylong missions but technological changes are expected to expand that timeframe to 6 months. ROVs are tethered to the surface, limiting their mobility, but they can transmit real time data. (Danielson and Weingartner 2007).

Research continues on remote sensing of spills in solid and broken ice conditions (ACS 2009b; MMS 2008, Vol. I). Alaska Clean Seas, the North Slope cleanup cooperative, has tested the use of Ground Penetrating Radar (GPR) to locate oil under solid ice; experiments in Norway have show GPR to be an effective tool (MMS 2008, Vol. I). In 2009 ACS intends to study the feasibility of using airborne GPR (ACS 2009b).

If pipelines were used in the development of the lease sale area, operators would follow the appropriate American Petroleum Institute recommended practices. They would inspect the pipelines regularly to determine if any damage was occurring and would perform regular maintenance. Preventive maintenance includes installing improved cathodic protection, using corrosion inhibitors, and continuing regular visual inspections.

4. 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. Plans must set forth measures designed to prevent spills and must have sufficient resources 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.

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 2007a)

a. <u>Incident Command System</u>

Oil spill responders are required to activate and use an Incident Command System (ICS) in the event of an actual or potential oil or hazardous material spill. The ICS system is designed to organize and manage responses to incidents involving a number of interested parties in a variety of activities. Because oil spills usually involve multiple jurisdictions, the joint federal/state response contingency plan incorporates a unified command structure in the oil and hazardous substance discharge ICS. The unified command consists of the Federal On-Scene Coordinator, the State On-Scene Coordinator, the Local On-Scene Coordinator, and the Responsible Party On-Scene Coordinator. The ICS is organized around five major functions: command, planning, operations, logistics, and finance/administration (ADEC 2007a).

The Unified Command jointly makes decisions on objectives and response strategies; however, only one Incident Commander is in charge of the spill response. The Incident Commander is responsible for implementing these objectives and response strategies. If the Responsible Party is known, the Responsible Party Incident Commander may remain in charge until or unless the On-Scene Coordinator with jurisdictional authority decides that the Responsible Party's response to the spill is unsatisfactory (ADEC 2007a).

b. <u>Response Teams</u>

The Alaska Regional Response Team (ARRT) monitors the actions of the Responsible Party. 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 Environmental Protection Agency. 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 (ARRT 1999). 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 (ADEC 2006a). 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 (ARRT 1999). Each operator identifies a spill response team (SRT) for their facility, and each facility must have an approved spill contingency plan. Company teams provide on-site, immediate response to a spill event. The SRTs are integrated into the North Slope Spill Response Team (NSRT), comprised of 115 field responders per day. The North Slope operators who furnish the SRTs from their employee and contractor staffs have committed to make the SRTs available on a North Slope-wide basis for up to 72 hours upon call-out (Morris 2009b).

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 Responsible Party calls in its response organization. The Spill Response Team (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 would be 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.

c. Training

Individual members of the SRT train in basic spill response. Alaska Clean Seas, 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 Types and Applications, Detection of Oil in Winter, and Behavior of Oil in Broken Ice. 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 2009b). ACS has five labor categories (ACS 2008, Vol. I). 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. These 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.

d. Response Organizations

Alaska Clean Seas (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 and in the coastal and OCS waters off the coast of the North Slope of Alaska. 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. 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 2009b).

The operating area includes the North Slope, the Alyeska Pipeline from Pump Station 1 to Milepost 167, and Beaufort Sea nearshore and select OCS waters. Members include Alyeska Pipeline Service Company, Anadarko Petroleum Corporation, BP Exploration (Alaska) Inc., Brooks Range Petroleum Corporation, Chevron, ConocoPhillips Alaska Inc., Eni Petroleum, ExxonMobil Production Company, FEX L.P., Pioneer Natural Resources (USA), and Shell Exploration and Production Company (ACS 2009b).

i. ACS Responders and Mutual Aid Agreements

Members 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 76 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 2009b).

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 a number of variables. As a general guide, immediate response to small spills in the nearshore area of the Beaufort Sea will be available within the first few hours using pre-staged response resources and personnel from within the responsible party's unit. With offshore boom, vessels, and skimmer systems pre-staged at West Dock, an offshore first-response task force consisting of ACS personnel and equipment could be on site within hours of notification, depending on weather conditions. In the event of a catastrophic spill requiring full mobilization of North Slope resources, oil spill response barges would be equipped and placed into service to assist with containment, recovery, transfer, and lightering operations.

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 North Slope Spill Response Team (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, Vol. I). ACS has 76 full time staff on the North Slope and in Anchorage (ACS 2009b); about half of ACS' employees and contractors are located on the North Slope and all are available for response operations. ACS has available a minimum of 115 spill response personnel on the North Slope each day (ACS 2009b).

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 have the training to do so.

ii. Initiation of the Incident Management Team

Response actions vary greatly with the nature, location, and size of the spill. General response activities may include:

- Locate and stop the spill if possible;
- Estimate the spill amount, determine the substance's chemistry, and estimate the trajectory;
- Determine what equipment would most effectively recover spilled oil;
- Mobilize appropriate equipment to confine spilled oil or to protect especially sensitive areas from oiling; and,
- Assess the damage to oiled areas, develop a plan for cleanup, and implement it.

Response equipment might include boats, earth-moving equipment, airplanes, helicopters, 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.

iii. Equipment

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, Vol. I). Additional equipment and trained personnel are available through ACS' agreements with contractors or master services agreements.

Spill response equipment warehouses, storage yards, and satellite areas are strategically located in each operating field and at three separate locations in Deadhorse (ACS 2009a). With assistance from ACS Base, field assigned ACS technicians support the operating area facilities and sites, while the Deadhorse locations are managed by ACS Base personnel. ACS Base in Deadhorse contains a small Emergency Operations Center for use by the member companies. Emergency Operations Centers are also located at Alpine, Kuparuk, Milne Point, and the Prudhoe Bay Operations Center and are available through the Mutual Aid Agreement (ACS 2009b). Mobile facilities are also available.

Major equipment assets owned by ACS and its member companies (ACS 2009b):

- Over 287,000 feet of oil containment boom, plus about 19,000 feet of fire boom;
- 185 skimmers, which may remove 7,301 bbl/hour of spilled oil;
- 8 helitorch aerial ignition systems;
- 96 vessels;
- 2 128-barrel and 12 249-barrel mini-barges; and one 650-barrel barge;
- Various sizes of storage tanks and bladders;
- Wildlife hazing and stabilization equipment;
- Pumps, powerpacks, and support equipment specifically designed to augment spill response;
- Telecommunications system that supports both day-to-day and spill response, including three mobile command centers with full radio, phone, and fax capabilities;
- Contracts with off-slope companies to provide over 300 additional, qualified spill responders;
- A small Emergency Operations Center at ACS' base in Deadhorse, plus Emergency Operations Centers at Alpine, Kuparuk, Milne Point, and Prudhoe Bay Operations Center;
- Specialized equipment to conduct alternative response measures, including conducting in-situ burning operations; and
- Mobile facilities and support equipment for the capture, cleaning, and rehabilitation of oiled birds.

Courtesy Alaska Clean Seas

Alaska Clean Seas oil spill drill.

Within the state of Alaska, there are other spill response organizations, each with their respective areas of operation and commitment. Cook Inlet Spill Prevention and Response, Inc. (CISPRI) in the Cook Inlet and Alyeska Pipeline's SERVS (Ship Escort Response Vessel System) in Prince William Sound are two of the major Alaskan organizations with which ACS has developed close working relationships to facilitate immediate support of a major spill response effort anywhere within Alaska. Should it become necessary, ACS can request additional equipment from these other cooperatives and industry sources (ACS 2008, Vol. I).

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 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, Vol. I). 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, Vol. I).

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.

iv. 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 responsible party (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 available off 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 subcontractors (Master Service Agreements) (ACS 2009b), as well from across the U.S. and other countries (ACS 2008, Vol. I). Response strategies are set forth in ACS' Technical Manual, providing specific scenarios for environmental and seasonal conditions found on the North Slope.

v. Research and Development

Building on studies done regarding Arctic oil spill response, ACS wrote a technical manual for spill response on the North Slope and Beaufort Sea (ACS 2008, Vol. I, II, III). 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 oil discharge prevention and contingency 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 represented 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 viscous oil pumping, detecting and tracking oil under ice, and alternative response options (ACS 2009b). ACS also manages research and development projects for BP Exploration (Alaska), 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. Over 10 years an average of $200,000 annually will be devoted to Arctic spill response research and development. ACS is considered an industry leader in the research of in-situ burning techniques and in-situ burning of emulsified oil (ACS 2009b).

ACS recently completed or is currently engaged in research projects (ACS 2009b):

- Testing Ground Penetrating Radar (GPR) to detect oil in and under snow and ice and is considering testing airborne deployment.
- Participating in a multi-year research and development project by SINTEF to test mechanical and non-mechanical responses to spills in ice, providing fire boom for field testing and

expertise to the Mechanical Recovery Working Group, In-Situ Burn Working Group, and Generic Contingency Plan Working Group.

- Completed "Produced Water Spills on the North Slope of Alaska, An Experimental Design for Winter Cleanup" plan. Seawater spills can injure fragile Arctic tundra, but cleanup measures may also damage tundra. The test plan was developed to help determine the pH levels of salt concentrations that would not cause unacceptable injury to the underlying tundra.
- Completed the "Winter Crude Oil Releases on the North Slope Snow Covered Tundra, An Experimental Cleanup Strategy" plan, to help develop cleanup standards for lightly oiled snow.
- Joined in a project to test new high volume oleophilic skimmers, which recover smaller quantities of water, thus decreasing the need for storage of recovered oil and water.

Research and development projects proposed for 2009 include:

- Continuation of research and development Program for Oil Spill Response in Ice Infested and Arctic Waters
- Continuation of High Volume Oleophilic Skimmer Tests
- Airborne Ground Penetrating Radar
- Nuclear Magnetic Resonance
- Improving Methods for Recovering Residues from In-Situ Burning of Marine Oil Spills
- Tundra Treatment Guidelines Update
- Suitcase Remote Sensing.

e. Geographic Response Strategies

A component of the state's spill contingency plans, Geographic Response Strategies (GRS) provide priorities and response strategies for the protection of selected sensitive areas to assist first responders to an oil spill. The GRS are intended to list the sensitive resources of a particular area and the response tactics, equipment, personnel, and logistical information necessary to protect these sensitive resources. The North Slope Subarea does not presently have any official GRS. Instead, the subarea plan relies on Alaska Clean Seas' *Technical Manual*, which presents ACS' maps of priority protection sites. ACS has mapped sites from Point Hope east to the Canadian border (ACS 2008, Vol. II).

In the example included in Figure 6.4, for an area at Prudhoe Bay, ACS identifies two priority protection sites and the times of year those areas are most sensitive. It also identifies general sensitivities, air access, vessel access and hydrographic conditions, countermeasure considerations, and the location of staging areas and pre-staged equipment.

Sensitivity Information

PRIORITY PROTECTION SITES

SITE NO.	DESCRIPTION	SENSITIVITY	TACTIC	EST. BOOM
PS10	Creek mouth north of LGI	Most sensitive during open water season. Inundated low-lying tundra shoreline.	C-13 or C-14	100'
PS11	Tidal inlet, west side of West Dock base	Most sensitive during open water season, when oil could drift into inlet. Inundated low-lying tundra shoreline.	C-13 or C-14	1,000'

GENERAL SENSITIVITIES

- Coastal areas support high concentrations of breeding, nesting, brood-rearing, and molting waterbirds during the summer.
- Concentrations of swans, ducks, geese, and shorebirds are present here in June before open water is present elsewhere.
- Shoreline and offshore areas support molting Oldsquaws and elders, and brood-rearing elders. This is also a staging area for migrating Phalaropes (shorebirds). Birds are present in June through September.
- High concentrations of brood-rearing and molting Snow Geese are present in July and August.
- This is a Brant nesting, brood-rearing, and molting area. Birds are present from May through August.
- Pairs of Spectacled Elders have been found in this area.
- Plan to deploy bird-hazing systems during the open-water season.

ACS Tech. Manual Vol. 2, 12/03 *NOTE: All values given on these pages are for planning purposes only.*

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Figure 6.4. ACS priority protection site at Prudhoe Bay.

Response Considerations

AIR ACCESS*

- Deadhorse airport (Sheet 78) is located approximately 10 miles south of LGI.

VESSEL ACCESS* AND HYDROGRAPHIC CONDITIONS

- Outer portions of Prudhoe Bay have water depths of 6 to 9 ft and afford good holding anchorage with protection from all but northwest winds. Inner bay has shoals across most of the entrance, with water depths of 2 to 6 ft.
- The best marine access route to Prudhoe Bay parallels the west shore at a distance of 0.4 mile and has depths of 4 ft.
- There are boat launches at West Beach State and at the south end of West Dock.
- There is high sediment transport in westerly direction along shore due to Sagavanirktok River discharge.
- Eddies and reduced current velocities in Prudhoe Bay cause extensive shoaling and migration of barrier islands.

COUNTERMEASURES CONSIDERATIONS

- Sand-gravel beaches on the interior of Prudhoe Bay are quite narrow and interrupted by vegetated shorelines, making large machinery impractical.

STAGING AREAS AND PRESTAGED EQUIPMENT

- The West Dock Staging Pad is a staging area.

PRESTAGED EQUIP. AREA	LOCATION	ITEM	QUANTITY	TYPE
EQA-3	West Beach State	Boom Anchor System	2,000' 1	8" x 6" river

*See the latest *Supplement, Alaska* and United States Coast Pilot for current information on air and vessel access, respectively.

NOTE: All values given on these pages are for planning purposes only.

-continued-

Figure 6.4 Page 2 of 3.

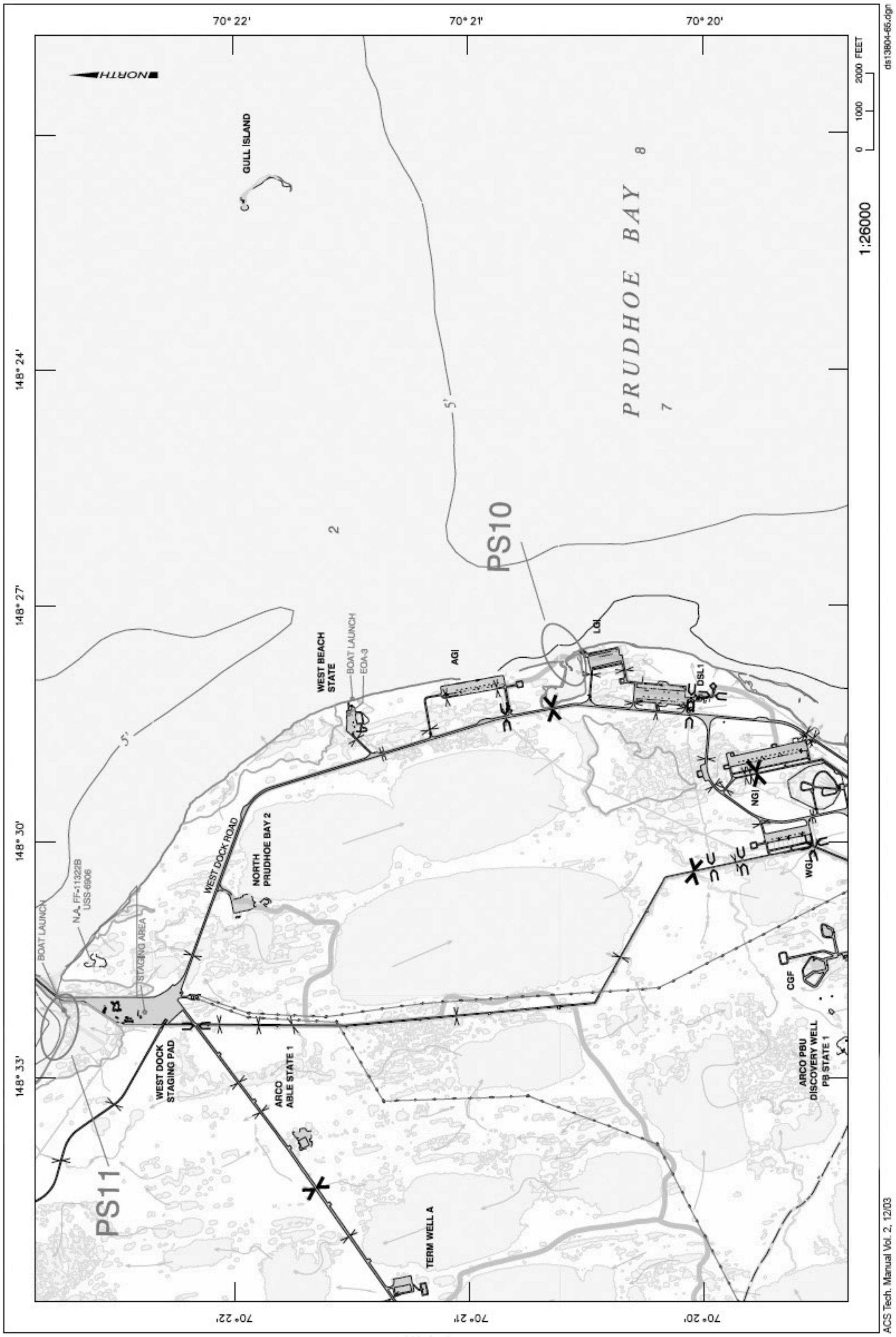

Figure 6.4 Page 3 of 3.

5. Cleanup and Remediation

The state's priorities for oil spill response are

- 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 2007a).

Cleanup plans, regardless of the location and nature of the spill, must balance the objectives of maximizing recovery and minimizing ecological damage. Many past cleanup operations have caused as much or more damage than the oil itself. 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 the Arctic–extreme cold, ice, and darkness. The North Slope/Beaufort Sea 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 2007a). However, spills that occur during the summertime risk impacting the diverse species that use North Slope 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.

a. **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; this is called weathering–spreading, evaporation, dispersion, dissolution, and emulsification (BLM 2008b, Vol. II, Chapter IV). Oil spreads quickly, with wind waves and water turbulence being principal factors (Doyle et al. 2008). Evaporation allows lighter components of oil to evaporate; evaporation increases as oil spreads and in rougher seas and higher temperatures. Dispersion 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. Emulsification occurs when oil and another liquid (seawater) combine, with seawater suspended within the oil; turbulence promotes emulsification. The resulting emulsion is viscous and more persistent than the original oil. 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 on-water storage requirements, and negatively impact the oil's ability to burn (MMS 2008, Vol. I, Chapter Four).

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.

Oil on water spreads and quick intervention is critical. The fate and behavior of oil spilled in the Beaufort Sea 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). 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 percent 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 Carter 1996). Understanding these processes is critical to decisions about cleaning spilled oil.

b. <u>Cleanup Techniques</u>

The best 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 6.6 lists cleanup objectives and techniques that may be applicable to each objective. Table 6.7 compares the advantages and disadvantages of cleanup techniques for crude oil in terrestrial and wetland ecosystems (Jorgenson and Carter 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 re-establish the ecological conditions that preceded the spill and usually includes a monitoring program to access the results of the restoration activities (Jorgenson and Carter 1996).

Spill recovery techniques are generally considered mechanical (e.g., boom and skimmers) or non-mechanical (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' Technical Manual examines North Slope/Beaufort Sea ecosystems and presents cleanup tactics for each (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 (MMS 2008, Vol. I, Chapter Four) that collect oil when it adheres to the surface of the brush or rope. 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 on-water storage. Containment and recovery may be slow and may not remove all the oil.

Table 6.6. Objectives and techniques for cleaning up crude oil in 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 Carter 1996.

Table 6.7. 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 Carter 1996.

Dispersants and in-situ burning are non-mechanical 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 on-water spills (ADEC 2006b) and are not used on broken or solid ice. 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, Vol. I, Chapter Four). ACS and the North Slope operators do not store dispersants or application equipment on the North Slope, because offshore activities to date have occurred in shallow nearshore waters (MMS 2008, Vol. I, Chapter Four).

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 et al. 2008). MMS considers in-situ burning the preferred method of non-mechanical response for icy waters (MMS 2008, Vol. I, Chapter Four).

Burning rapidly removes oil from the environment, particularly when compared to 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.

Ice, present in the nearshore Beaufort Sea for over 280 days of each calendar year, may both facilitate and constrain cleanup. Broken ice, ice coverage of more than 10 percent and wave height of less than 1 foot, may hinder the use of containment boom, leading to boom failure and the likelihood of loss due to ice encounters (ADEC 2006b). In an oil spill under the ice, oil can be absorbed within the ice matrix. Landfast ice is mobile, so ice may melt or breakup far removed from the location where the oil was entrained, releasing the oil in the new location (Danielson and Weingartner 2007). Oil spilt during freeze-up or break-up may be particularly difficult to clean up (ADEC 2007a). ACS, the industry's oil spill cleanup cooperative, continues to participate in research on effective cleanup in and on ice (ACS 2009b).

The North Slope Borough has discouraged development in the Beaufort Sea because of its concern about risks to subsistence and its concern that there are insufficient resources and technology to stop, recover, and cleanup an offshore spill at any time of year (NSB 2005). In its 2005 Background Report for NSB's Comprehensive Plan, the North Slope Borough disagreed with findings, like the ones contained here and in MMS's most recent DEIS for the Beaufort Sea (MMS 2008), about the behavior of spilled oil in and on ice and broken ice and industry's ability to contain and clean up a spill. Specifically, the borough disagreed that

- Spills onto ice would be prevented from spreading rapidly by snow and ice roughness;
- Spills in broken ice conditions would not spread as rapidly as on open water; and
- Oil leaks under nearshore sea ice would likely not spread until breakup due to slow under ice currents (NSB 2005).

The borough expressed concerned that under-ice currents would impact the spread of oil and that ice would substantially limit boat-based cleanup. The borough said there have been no oil spill recovery techniques that have been effectively designed or tested to clean up oil in spring broken ice conditions, fall freeze-up conditions, or under solid ice and that resources and technology to stop, recover, and clean up an oil spill in an offshore environment are lacking. The borough expressed concern about the lack of an ice-breaking barge on the North Slope for oil spill response and stated there are limited resources and techniques available for handling under-ice spills. The borough's concerns led it to suggest that development activities, particularly drilling, be seasonally limited to avoid certain conditions (offshore during broken ice, freeze-up and slush ice; under ice in frozen conditions; and onshore during summer, unless drilling occurs on an onshore gravel pad) (NSB 2005).

It is possible that some of the borough's concerns will be alleviated by technological advances in monitoring and constructing pipelines (see Sections F(2)(a) and F(3)(b)) and ongoing oil spill response research and development studies (see also Section F(4)(d)(v)). These projects have studied oil and ice interactions over the last 30 years. Beginning with the research conducted offshore in the Canadian Beaufort Sea and followed by projects in the Alaskan and Norwegian Arctic, scientists and responders have studied oil behavior and developed and tested methods and tools to mitigate the effects of an oil spill in, on, or under ice. Arctic spill research projects have explored, under various ice conditions, aspects including oil weathering characteristics, spreading under ice, encapsulation and migration, remote sensing, trajectory modeling, and the testing of in-situ burning, dispersants, and conventional containment and recovery equipment (ACS 2009b).

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). MMS is providing funding for a multi-national industry/government sponsored oil in ice response test in Norway which will provide additional data on spill responses in broken ice conditions (MMS 2008, Vol. I, Chapter Four).

6. Regulation of Oil Spill Prevention and Response

a. Federal Statutes and Regulations

Section 105 of the Comprehensive Environmental Response, Compensation, and Liability Act of 1980 (CERCLA) (42 USC §9605), and §311(c)(2) of the Clean Water Act, as amended (33 USC §1321(c)(2)) require environmental protection from oil spills. CERCLA and the Clean Water Act require a National Oil and Hazardous Substances Pollution Contingency Plan (40 CFR §300; 33 USC §1321(d)). Under these regulations, the spiller must plan to prevent and immediately respond to oil and hazardous substance spills and be financially liable for any spill cleanup. If the pre-designated Federal On-Scene Coordinator (FOSC) determines that neither timely nor adequate response actions are being implemented, the federal government will respond to the spill, and then seek to recover cleanup costs from the responsible party.

The Oil Pollution Act of 1990 (OPA 90) requires the development of facility and tank vessel response plans and an area-level planning and coordination structure to coordinate federal, regional, and local government planning efforts with the industry. OPA 90 amended the Clean Water Act (§311(j)(4); 33 USC §1231(j)) and established area committees and area contingency plans as the primary components of the national response planning structure. In addition to human health and safety, these area committees have three primary responsibilities:

- Prepare an area contingency plan;

- Work with state and local officials on contingency planning and preplanning of joint response efforts, including procedures for mechanical recovery, dispersal, shoreline cleanup, protection of sensitive areas, and protection, rescue and rehabilitation of fisheries and wildlife; and,
- Work with state and local officials to expedite decisions for the use of dispersants and other mitigating substances and devices.

In Alaska, the area committee structure has incorporated state and local agency representatives, and the jointly prepared plans coordinate the response activities of the various governmental entities that have responsibilities regarding oil spill response. The area contingency plan for Alaska is the Unified Plan. Since Alaska is so large and geographically diverse, the federal agencies have found it necessary to prepare sub-area contingency plans, also discussed in the Government Contingency Plans section below. OPA 90 also created two citizen advisory groups: the Prince William Sound and the Cook Inlet Regional Citizens Advisory Councils. These non-profit organizations provide citizen oversight of terminal and tanker operations that may affect the environment in their respective geographic areas. They also foster a long term partnership between industry, government, and citizens and carry out responsibilities identified in section 5002 of OPA 90. The groups provide recommendations on policies, permits, and site-specific regulations for terminal and tanker operations and maintenance and port operations, monitoring terminal and tanker operations and maintenance, and reviewing contingency plans for terminals and tankers and standards for tankers.

b. Alaska Statutes and Regulations

As discussed above and in Chapter Seven, ADEC is the agency responsible for implementing state oil spill response and planning regulations under AS 46.04.030. In 2006, ADEC adopted new regulations (18 AAC 75) for oilfield flowlines, new construction, and maintenance standards that apply to oil tanks and pipeline facilities. Additionally, ADEC is placing increased emphasis on oil spill prevention training.

ADF&G and ADNR support ADEC in these efforts by providing expertise and information. The industry must file oil spill prevention and contingency plans with ADEC before operations commence. ADNR reviews and comments to ADEC regarding the adequacy of the industry oil discharge prevention and contingency plans (C-plans).

c. Industry Contingency Plans

C-plans for exploration facilities must include a description of methods for responding to and controlling blowouts, the location and identification of oil spill cleanup equipment, the location and availability of suitable drilling equipment, and an operations plan to mobilize and drill a relief well. If development and production should occur, additional contingency plans must be filed for each facility before commencement of activity, as part of the permitting process. Any vessels transporting crude oil from the potential development area must also have an approved contingency plan.

AS 46.04.030 provides that unless an oil discharge prevention and contingency plan has been approved by ADEC, and the operator is in compliance with the plan, no person may:

- Operate an oil terminal facility, a pipeline, or an exploration or production facility, a tank vessel, or an oil barge; or
- Permit the transfer of oil to or from a tank vessel or oil barge.

Parties with approved plans are required to have sufficient oil discharge containment, storage, transfer, cleanup equipment, personnel, and resources to meet the response planning standards for the particular type of facility, pipeline, tank vessel, or oil barge (AS 46.04.030(k)). Examples of these requirements are:

- The operator of an oil terminal facility must be able to “contain or control, and clean up” a spill volume equal to that of the largest oil storage tank at the facility within 72 hours. That volume may be increased by ADEC if natural or manmade conditions exist outside the facility that place the area at high risk (AS 46.04.030(k)(1)).
- Operators of exploration or production facilities or pipelines must be able to “contain, control, and clean up the realistic maximum oil discharge within 72 hours” (AS 46.04.030(k)(2)). The “realistic maximum oil discharge” means the maximum and most damaging oil discharge that [ADEC] estimates could occur during the lifetime of the tank vessel, oil barge, facility, or pipeline based on (1) the size, location, and capacity; (2) ADEC’s knowledge and experience with such; and (3) ADEC’s analysis of possible mishaps (AS 46.04.030(r)(3)).

Discharges of oil or hazardous substances must be reported to ADEC on a time schedule depending on the volume released, whether the release is to land or to water, and whether the release has been contained by a secondary containment or structure. For example, 18 AAC 75.300(a)(1)(A)-(C) requires the operator to notify ADEC as soon as it has knowledge of the following types of discharges:

- Any discharge or release of a hazardous substance other than oil;
- Any discharge of or release of oil to water; and,
- Any discharge or release, including a cumulative discharge or release, of oil in excess of 55 gallons (1.31 bbl) solely to land outside an impermeable secondary containment area or structure.

The discharge must be cleaned up to the satisfaction of ADEC, using methods approved by ADEC. ADEC will modify cleanup techniques or require additional cleanup techniques for the site as ADEC determines to be necessary to protect human health, safety, and welfare, and the environment (18 AAC 75.335(d). ADF&G and ADNR advise ADEC regarding the adequacy of cleanup.

A C-plan must describe the existing and proposed means of oil discharge detection, including surveillance schedules, leak detection, observation wells, monitoring systems, and spill-detection instrumentation (AS 46.04.030; 18 AAC 75.425(e)(2)(E)). A C-plan and its preparation, application, approval, and demonstration of effectiveness require a major effort on the part of facility operators and plan holders. The C-plan must include a response action plan, a prevention plan, and supplemental information to support the response plan (18 AAC 75.425). These plans are described below.

The Response Action Plan (18 AAC 75.425(e)(1)) must include an emergency action checklist of immediate steps to be taken if a discharge occurs. The checklist must include:

- Names and telephone numbers of people within the operator’s organization who must be notified, and those responsible for notifying ADEC;
- Information on safety, communications, and deployment and response strategies;
- Specific actions to stop a discharge at its source, to track the location of the oil on open water, and to forecast the location of its expected point of shoreline contact to prevent oil from affecting environmentally sensitive areas;
- Procedures for boom deployment, skimming or absorbing, lightering, and estimating the amount of recovered oil;
- Plans, procedures, and locations for the temporary storage and ultimate disposal of oil contaminated materials and oily wastes;
- Plans for the protection, recovery, disposal, rehabilitation, and release of potentially affected wildlife; and,

- If shorelines are affected, shoreline cleanup and restoration methods.

The Prevention Plan (18 AAC 75.425(e)(2)) must:

- Include a description and schedule of regular pollution inspection and maintenance programs;
- Provide a history and description of known discharges greater than 55 gallons (1.31 bbl)that have occurred at the facility, and specify the measures to be taken to prevent or mitigate similar future discharges;
- Provide an analysis of the size, frequency, cause, and duration of potential oil discharges, and any operational considerations, geophysical hazards, or other site-specific factors, which might increase the risk of a discharge, and measures taken to reduce such risks; and,
- Describe existing and proposed means of discharge detection, including surveillance schedules, leak detection, observation wells, monitoring systems, and spill-detection instrumentation.

The Supplemental Information Section (18 AAC 75.425(e)(3)) must:

- Include a facility description and operational overview, describing oil storage, transfer, exploration, or production activities; the number and type of oil storage containers and the type and amount of oil stored; the normal routes of oil cargo vessel; procedures for loading or transferring oil; and a description of flow and gathering lines and processing facilities;
- Show the response command system; the realistic maximum response operation limitations such as weather, sea states (roughness of the sea), tides and currents, ice conditions, and visibility restrictions; the logistical support including identification of aircraft, vessels, and other transport equipment and personnel;
- Include a response equipment list including containment, control, cleanup, storage, transfer, lightering, and other related response equipment;
- Provide information regarding non-mechanical response, such as in-situ burning or dispersants, including an environmental assessment of such use;
- Provide information regarding the oil spill primary response action contractor;
- Include a detailed description of the training programs for discharge response personnel;
- Provide a plan for protecting environmentally sensitive areas and areas of public concern; and,
- Include any additional information and a bibliography.

The Best Available Technology Section (18 AAC 75.425(e)(4)) must:

- Identify technologies applicable to the applicant's operation that are not subject to response planning or performance standards;
- For each applicable technology listed, the plan must identify and analyze all available technologies; and,
- Include a written justification that the technology proposed to be used is the best available for the applicant's operation.

The Response Planning Standard Section (18 AAC 75.425(e)(5)) must include a calculation of the applicable response planning standards, including a detailed basis for the calculation of reductions, if any, to be applied to the response planning standards.

The current statute allows the sharing of oil spill response equipment, materials, and personnel among plan holders. ADEC determines by regulation the maximum amount of material, equipment, and personnel that can be transferred, and the time allowed for the return of those resources to the original plan holder (AS 46.04.030(o)). The statute also requires the plan holders to “successfully demonstrate the ability to carry out the plan when required by [ADEC]” (AS 46.04.030(r)(2)(E)). ADEC regulations require that exercises (announced or unannounced) be conducted to test the adequacy and execution of the contingency plan. No more than two exercises are required annually, unless the plan proves inadequate. ADEC may, at its discretion, consider regularly scheduled training exercises as discharge exercises (18 AAC 75.485(a) and (d)).

d. Financial Responsibility

Operators must provide proof of financial ability to respond in damages (AS 46.04.040). Financial responsibility may be demonstrated by one or a combination of 1) self-insurance; 2) insurance; 3) surety; 4) guarantee; 5) approved letter of credit; or 6) other ADEC-approved proof of financial responsibility (AS 46.04.040(e)). Operators must provide proof of financial responsibility acceptable to ADEC as follows:

- Crude oil terminals: $50,000,000 in damages per incident
- Non-crude oil terminals: $25 per incident for each barrel of total non-crude oil storage capacity at the terminal or $1,000,000, whichever is greater, with a maximum of $50,000,000
- Pipelines and offshore exploration or production facilities: $50,000,000 per incident.
- Onshore production facilities:

  $20,000,000 per incident if the facility produces over 10,000 bbl per day of oil;
  $10,000,000 per incident if the facility produces over 5,000 bbl per day of oil;
  $5,000,000 per incident if the facility produces over 2,500 bbl per day but not more than 5,000 bbl per day of oil; and,
  $1,000,000 per incident if the facility produces 2,500 bbl per day or less of oil.
- Onshore exploration facilities: $1,000,000 per incident.
- Crude oil vessels and barges: $300 per incident, for each barrel of storage capacity or $100,000,000, whichever is greater
- Vessels and barges carrying non-crude oil: $100 per barrel per incident or $1,000,000, whichever is greater, with a maximum of $35,000,000.

The coverage amounts are adjusted every third year based on the Consumer Price Index for Anchorage (AS 46.04.045).

e. Government Contingency Plans

In accordance with AS 46.04.200, ADEC must prepare, annually review, and revise the statewide master oil and hazardous substance discharge prevention and contingency plan. The plan must identify and specify the responsibilities of state and federal agencies, municipalities, facility operators, and private parties whose property may be affected by an oil or hazardous substance discharge, as well as other parties with an interest in cleanup. The plan must incorporate the incident command system, identify actions to be taken to reduce the likelihood of a discharge of oil or a hazardous substance. Revisions are submitted for public and agency review. Announced or unannounced drills test the need for the plan’s sufficiency.

ADEC must also prepare and annually review and revise a regional master oil and hazardous substance discharge prevention and contingency plan (AS 46.04.210). The regional master plans must contain the same elements and conditions as the state master plan, but are applicable to a specific geographic area. The North Slope subarea plan was revised in April of 2007 (ADEC 2007a).

7. Mitigation Measures and Other Regulatory Protections

Recognition of the difficulties of containment and cleanup of oil spills has encouraged innovative and effective methods of preventing possible problems and handling them if they arise. Oil spill prevention, response, and cleanup and remediation techniques are continually being researched by state and federal agencies and the oil industry. Risk of effects from a spill can be avoided, minimized, and mitigated through preventive measures, monitoring, and rigorous response capability. Mitigation measures addressing the possibility of oil spills are included in this final best interest finding (see Chapter Nine). Additional site-specific and project-specific mitigation measures may be imposed as necessary if exploration and development take place.

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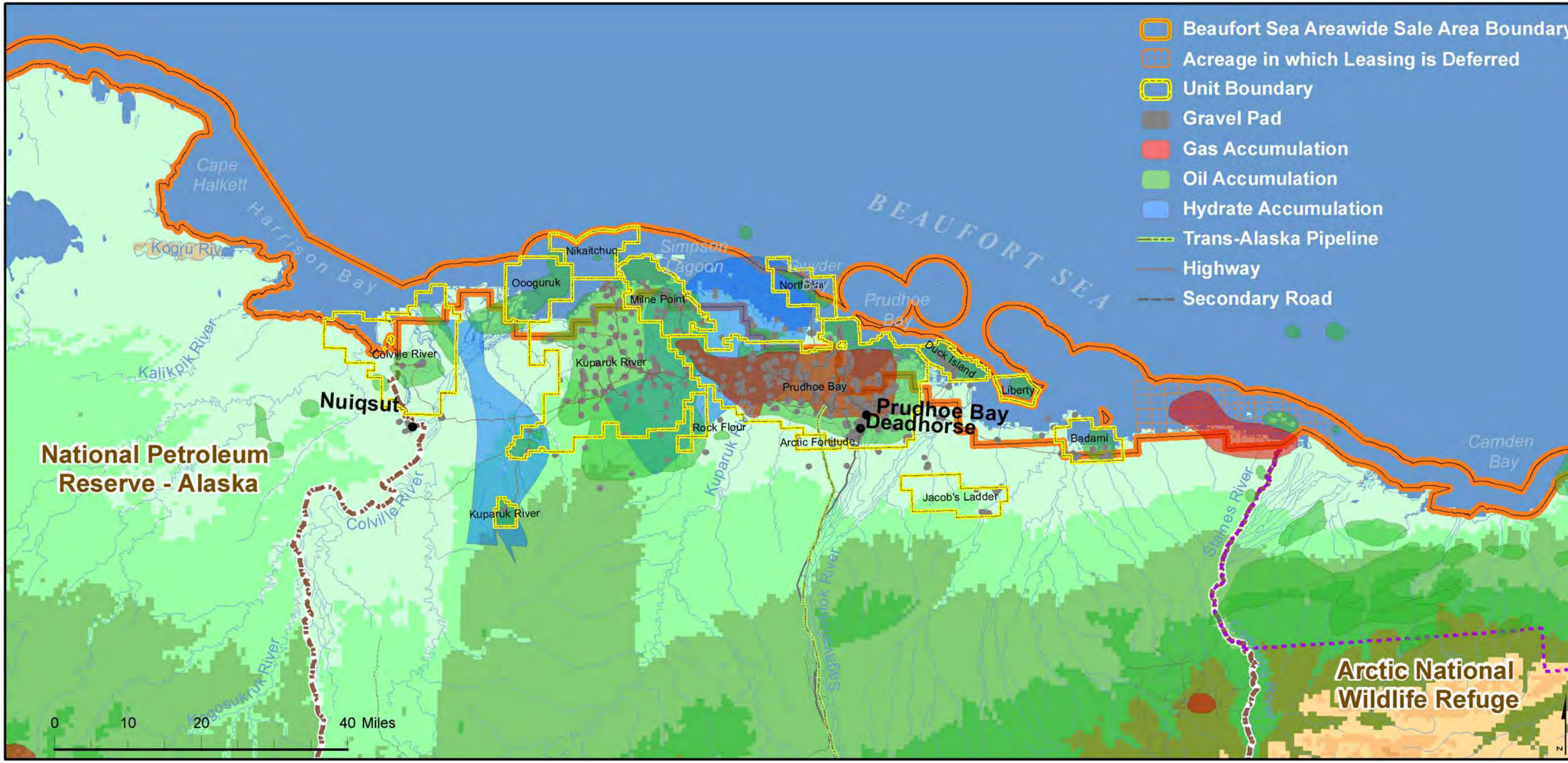
Maps



Notes: Information on this map is depicted only at a township or section level resolution. For detailed information regarding any specific area, interested individuals may consult the land records of one or more of the following agencies: ADNR, BLM, MMS, or NOAA. Discrepancies in boundary alignments are the result of merging multiple data sets from these various sources.

Map 6.1. Oil, gas, and hydrate accumulations, and infrastructure, in the Beaufort Sea area.