Chapter Six: Oil and Gas in Cook Inlet

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Chapter Six: Oil and Gas in Cook Inlet

A. Geology of Cook Inlet

The Cook Inlet Lowland encompasses an area that lies generally below an elevation of 1,000 feet. It is bordered by the Alaska and Aleutian ranges to the north and west and by the Talkeetna, Chugach, and Kenai mountains to the northeast and east. The marine waters of Cook Inlet, including its Turnagain Arm and Knik Arm extensions, divide the Cook Inlet Lowland into several natural subunits. These subunits consist of the Kenai Lowland to the east, the Kustatan Lowland to the west, the Susitna Lowland to the north, and the Matanuska Lowland to the northeast (Karlstrom 1964).

L. Silliphant, DO&G

Beluga River, west side Cook Inlet.

The Cook Inlet Lowland occupies a structural trough known colloquially as the Cook Inlet Basin. This basin is underlain by rocks of Quaternary, Tertiary, Mesozoic, and older age (Table 6.1). Three major fault zones border the Cook Inlet Basin: the Bruin Bay and Castle Mountain faults, to the west and north respectively, and the Border Ranges fault to the east and northeast. Tertiary sediments south of the Castle Mountain fault are estimated to be as thick as 26,000 feet at the structural axis of the basin (DO&G 2008b). North of the Castle Mountain fault these sediments are only on the order of 2,000 feet thick (Maynard 1987; DO&G 1998).

The lease sale area encompasses the Cook Inlet Basin and a small section due north of the Castle Mountain fault. Rock sequences with proven oil and gas potential underlie the region. Cook Inlet Basin surficial and bedrock geology are discussed in the following sections.

1. Surficial Geology

Modern topography of the Cook Inlet Lowland has been dominantly influenced by five episodes of Pleistocene glaciation and two post-Pleistocene glacial periods (Reger et al. 2007; Karlstrom 1964). During these glaciations, ice lobes fed directly into the Cook Inlet Basin from the surrounding mountain ranges. The advance and retreat of these glaciers are responsible for many of the distinctive land features present in and surrounding the Cook Inlet Basin today such as scraped and scoured valley floors, broad outwash plains, and alpine troughs. The unsorted deposits of gravel, sand, silt, and clay remaining after a period of glaciation are called glacial till. Moraines, which are linear piles of till laid down in fairly regular, low-lying hills, are the most common glacial deposit found in the region. Moraines represent a glacier's maximum advance during its given episode (Selkregg 1975).

The Kenai Peninsula, from Point Possession to the head of Kachemak Bay, and including Kenai, Soldotna, and Homer, contains numerous low, rolling glacial moraines and glacial depressions filled by lakes and muskeg. Many rivers and streams flow through this area. Soils range from gravely clay loam to gravely sand mantled with silty material and bands of volcanic ash (KPB 1990).

On the west side of Cook Inlet, the coastal lowlands between Tuxedni Bay and Granite Point consist of nearly level, poorly drained outwash plains deposited by large glaciers in the Aleutian Range and Chigmit Mountains. The outwash plains are braided with meandering and shifting stream channels. Most soils consist of sandy glacial outwash, silt, tidal sediments and gravelly river wash. The water table is high in most of this area with the exception of a few well-drained natural levees and ridges.

North of Granite Point, topography and soils are similar to the coastal lowlands on the east side of Cook Inlet, and consist of glacial moraines and depressions of gravely clay, sand, and silt composition (KPB 1990).

Table 6.1. Geologic time.

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

Notes: Adapted from U.S. Geological Survey Geologic Names Committee, 2007, Divisions of geologic time--Major chronostratigraphic and geochronologic units (USGS 2007).

2. Bedrock Geology

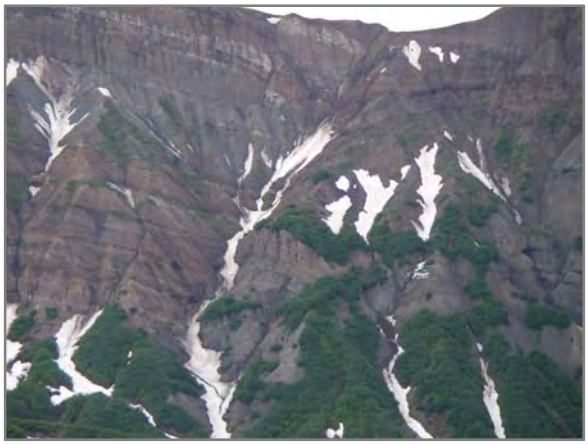
The Cook Inlet Basin is a geologically active convergent margin where the Pacific tectonic plate is subducting (i.e. plunging) beneath the North American tectonic plate. The Pacific plate is moving north-northwest sliding past the North American Plate near California and the Pacific Northwest. The northern edge of the Pacific plate extends from directly east of Asia through Prince William Sound and into central Alaska and is actively subducting beneath the North American plate in the vicinity of the Aleutian Islands and southern Alaska (Selkregg 1975). Active subduction and associated tectonic faulting have created the deep ocean Aleutian trench with an associated arc of volcanic islands known as the Aleutian archipelago, in addition to a chain of coastal mountain ranges including the Chugach and Kenai mountains. Tectonic processes of uplift and subsidence coupled with erosion, deposition, and sea level changes combined to form the Cook Inlet basin bedrock geology.

During late Paleozoic and early Mesozoic time (Table 6.1), sediments were deposited in a sea that occupied Southcentral Alaska. A volcanic island arc, similar in form to the modern Aleutian island arc, occupied a widespread area in the general vicinity of the now existing Alaska Range. The area occupied by the island arc was folded, faulted, and uplifted during Triassic time and provided the

source from which sediments were eroded and deposited in a southerly direction into the adjacent marine basin (Selkregg 1975; DO&G 1997).

Uplift and erosion of granitic bodies during Jurassic and Cretaceous time provided material for a thick sequence of continental shelf sediments deposited in an adjacent, low lying basin which extended from the southern Alaska Peninsula through the Cook Inlet region to the Copper River basin. Fine-grain sediments, rich in organic matter, were deposited creating source material for potential Tertiary age petroleum systems (Selkregg 1975; DO&G 1997). Concurrent with the Late Jurassic and Cretaceous continental shelf sediment deposition, Pacific plate subduction and fault slipping produced a thick accretionary wedge of oceanic sediments. This accretionary wedge was uplifted to form the Chugach and Kenai mountains.

During Tertiary time the trough between the granitic bodies to the west and northwest and the accretionary wedge to the east and north east was subsiding. A system of alluvial fans composed of gravels and coarse-grained sands developed along the mountain fronts. Streams reworked and transported sediment from the distal ends of the alluvial fans out into the floodplain. Swamps, highly vegetated interfluves, and flood basins provided biotic material that later developed into coals. The repetitive cycle of vegetative growth and subsequent flooding by sediment deposition resulted in thick accumulations of gravel, sandstone, siltstone, mudstone, and coal. The gravels and sands, possessing excellent porosity, would later become oil and gas reservoirs.



L. Silliphant, DO&G

Alluvial fans of West Foreland Formation, near Capps Glacier.

In the late Tertiary extensive right lateral faults, with associated dip-slip motion, developed along the Bruin Bay and Castle Mountain fault zones and the Border Ranges fault zone. This relative movement reactivated pre-existing structures throughout the basin and created a series of anticlinal and synclinal folds. Fold axes are generally subparallel to the basin margins and trend northeast-southwest. Many of these faulting-induced folds act as hydrocarbon traps and are sources of current oil and gas production today.

The southern edge of the Susitna Basin is generally interpreted as a northwestern extension of the Cook Inlet Basin. The structural style of the Susitna Basin is a combination of graben and half-graben basement faulting. Tertiary age formations in the southern Susitna Basin, although generally much thinner, are nearly identical to those found in Cook Inlet Basin proper. Eocene and Oligocene-age reservoir rocks however, appear to be missing from the Susitna Basin stratigraphic section. Jurassic age oil-prone source rocks, found in the Cook Inlet Basin, have not been found in wells or outcrops from the Susitna Basin (DO&G 1997).

B. Petroleum Potential

The area considered in this best interest finding has low to moderate petroleum exploration potential. This represents ADNR’s general 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.

Cook Inlet is a mature, producing petroleum basin which has seen extensive exploration and development over the past 40 years. The chances of finding undiscovered petroleum reservoirs is

reduced by the fact that extensive exploration has already taken place and there is a corresponding lack of major new discoveries.

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.

L. Silliphant, DO&G

Outcrop of permeable rock, Sterling Formation, near Clam Gulch.

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 fault 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 affects the depth and location where oil or gas may pool and form a reservoir. For a hydrocarbon reservoir to be producible, the reservoir rock must be of sufficient thickness and quality (good permeability and porosity), and must contain a sufficient volume or fill of hydrocarbons to be produced.

Another factor used by the division to assess the petroleum potential of the area considered in this best interest finding is the area's history of petroleum exploration and development. A well-documented history of petroleum discoveries and production indicates that petroleum reservoirs do exist.

Some portions of this area have higher potential because of more favorable geology and proximity to existing fields, while other portions of the area may have lower potential because they are either more distant from production areas, the geology is less favorable, or the exploration history is less encouraging. Areas with lower potential may still contain hydrocarbon accumulations.

The process of evaluating the oil and gas potential involves the use of data including seismic and well engineering information, which by law the division must keep confidential under AS 38.05.035(a)(9)(C). In order to protect these data, the division must generalize the assessment that 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 6.2 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 five-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 best interest finding, exploration licensing supplements the state's areawide oil and gas leasing program by targeting areas outside of known oil and gas provinces. The intent of licensing is to encourage exploration in areas far from existing infrastructure, with relatively low or unknown hydrocarbon potential, where there is a higher investment risk to the operator. Because bonus payments are required to win a lease, lease sales held in some of these higher-risk areas tend to attract little participation. Exploration licensing gives an interested party the exclusive right to conduct oil and gas exploration without this initial expense. Through exploration licensing the state receives valuable subsurface geologic information on these regions and, should development occur, additional revenue through royalties and taxes. (AS 38.05.131-134.)

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

Exploration	Development	Production
Permitting	Gravel pits, pads, and roads	Well work over (rigs)
Water usage	Dock and bridge construction	Gravel pads and roads
Environmental studies	Drilling rigs	Produced water
Seismic tests	Pipelines	Air emissions
Exploratory drilling rigs	Work camps	Pipeline maintenance
Land clearing	Permitting	Work camps
Drilling muds and discharges	Monitoring	Trucking
Gravel road beds	Well heads	
Work camp	Injection wells	
Increased air traffic	Seismic	
Temporary gravel pads		
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. Surface analysis includes the study of surface topography or the natural surface features of the area, near-surface structures revealed by examining and mapping exposed rock layers, and geographic features such as hills, mountains, and valleys. Geophysical exploration and exploration drilling are the primary activities that could result in potential effects to the Cook Inlet lease sale area. Geophysical surveys, primarily seismic, help reveal what the subsurface may look like. Geophysical exploration of the Cook Inlet area has been ongoing since prospectors discovered oil seeps in the early 20th century.

a. Geophysical Exploration

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

Seismic surveys are the most common type of geophysical exploration, and are typically conducted by geophysical companies under contract to leaseholders or as multi-client and speculative surveys run directly by the seismic contractors. At the survey location, an energy source is emitted into the subsurface and reflected energy waves are recorded by geophones and/or hydrophones, land and marine vibration-sensitive receivers. Different densities of rock layers beneath the surface result in a unique seismic profile that can be analyzed by geophysicists to determine subsurface structures and petroleum potential. Both two-dimensional (2D) and three-dimensional (3D) data are gathered from seismic surveys. In the Cook Inlet area, seismic surveys are conducted on land, in tidal areas, and in marine waters.

Land-based seismic surveys are usually conducted in winter to minimize effects to fish and wildlife habitats. Surveys can be run year round in uplands areas, but are limited to the winter season on wetlands, typically the end of October through the end of March, to best protect habitat and wildlife.

B. Havelock, DO&G

A Tucker SnoCat, used for winter access.

To conduct a seismic survey, source and receiver locations are surveyed using GPS (Global Positioning Systems) and laid out in predesigned patterns. For 2D data, the receivers and sources lie in as straight a line as possible given the terrain, 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.

In areas of high habitat sensitivity, such as wildlife and game refuges, heli-portable crews and/or backpackers are used to transport equipment. In more accessible areas, narrow tracked vehicles are used for transport. If needed to facilitate access, mulchers are used to clear brush, small alders and willows in 2-3 meter wide paths. Mulchers are not used in old growth or larger trees. Surveys now use

global satellite positioning instruments, making the past practice of long clear-cuts through forests for line-of-sight measurements unnecessary.

Multiple seismic sources can be used on land surveys, based on the terrain and conditions, including explosives, weight drop, and hydraulic devices (vibrator trucks).

Explosives may be placed into drill holes and detonated, or, much less commonly, they may be suspended on stakes above the ground (Poulter method). When buried, drill holes are typically 20-30 feet deep with 2.5-5 pounds of explosives set at the bottom of the hole. Holes are either drilled with track-mounted drills or, if in remote or sensitive areas, drills are slung into position by helicopters. Soil is disturbed in the immediate vicinity of the explosive charges placed into the ground. At locations with existing developments, allowable maximum peak particle velocity is mapped and if explosives are contra-indicated, vibrators or a weight drop are used to produce the seismic wave energy.

Vibroseis, a more common practice, utilizes a vibrator as the energy source. A vibrating plate is attached to a low ground pressure vehicle and creates a vibration of continuously varying frequency to put energy into the ground, typically lasting four seconds or longer. This method is less destructive than an impulsive explosive source, where all the energy is imparted in an instant.

B. Havelock, DO&G

Example of vibroseis trucks conducting a seismic survey.

Finally, a weight drop method can be used. The weight drop mechanism is transported via narrow tracked vehicles and is becoming a more routine acquisition source. Depending on the location, terrain and varying vegetation cover, several energy source techniques might be needed for the same project.

In intertidal (transition) zones, either shallow hole explosive sources at low tide, or very shallow towed airguns at high tide can be used. The receivers are typically housed in cables laid directly on the mud. Transition surveys are usually acquired from mid March through mid May, and from September until freeze-up. The season is limited by protections for fishing, wildlife, and recreational users, as well as safety concerns due to ice formation and flows.

Seismic surveys may also be conducted in marine waters, usually between April and mid-November. 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. Marine seismic equipment consists of an airgun array for the energy source, hydrophones to detect sound, 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, consists of several sub-arrays, each containing several airguns of various sizes. Hydrophones, which detect the sound energy waves generated by the airguns and reflected back from the sub-surface geologic boundaries, 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. Due to extreme tides and currents in Cook Inlet waters, towing multiple cables is problematic; more than two at a time is unusual here. For some seismic surveys, the detectors and cables are placed directly on the bottom (ocean bottom cable, or OBC) where they remain stationary as the shooting boat traverses across them.

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 and a lower energy seismic source than surveys targeting oil and gas potential, and use a much shorter cable.

b. Exploration Drilling

Courtesy Pioneer Natural Resources, Alaska

Rowan-68 rig drilling the Hansen 1AL1 exploration well near Anchor Point.

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 best 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:

- Special 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 to keep the hole from caving in; seal off rock formations; seal the well bore from groundwater; and provide 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 produces, is capped, or is plugged and abandoned.

When drilling 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. Roads are 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, if necessary a fuel storage area, 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. 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:

Courtesy ConocoPhillips

Sunfish prospect jack-up drilling rig.

- 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 from directional drilling (Appendix C) from shore, jackup rigs are the most likely to be used in Cook Inlet for exploratory wells, as they are best suited to withstanding the very large currents and tidal variations experienced here. These rigs 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. 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 jackup is positioned at the drill site, the legs are jacked down until they rest on the seabed. The hull is then jacked up above the water’s surface until a sufficient gap exists to accommodate 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 Chapter 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 reserve pit. If necessary, a flare pit may be constructed off of 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 6.1 depicts a production wellbore schematic for Cook Inlet.

B. Havelock, DO&G

Typical producing gas well, Cook Inlet area.

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. Sometimes a well is 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.

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 that conducts hearings to review drilling and development to ensure regulatory compliance.

Natural gas is occasionally flared for safety reasons. Flaring is "the controlled burning of natural gas at a well site or facility; venting is the release of uncombusted natural gas to the atmosphere" (Centre for Energy 2008). However, operators in Alaska are required to minimize the volume of gas released, burned, or permitted to escape into the air (20 AAC 23.235(c)). Operators must report monthly to AOGCC any flaring event lasting over an hour. AOGCC investigates these incidents to determine if

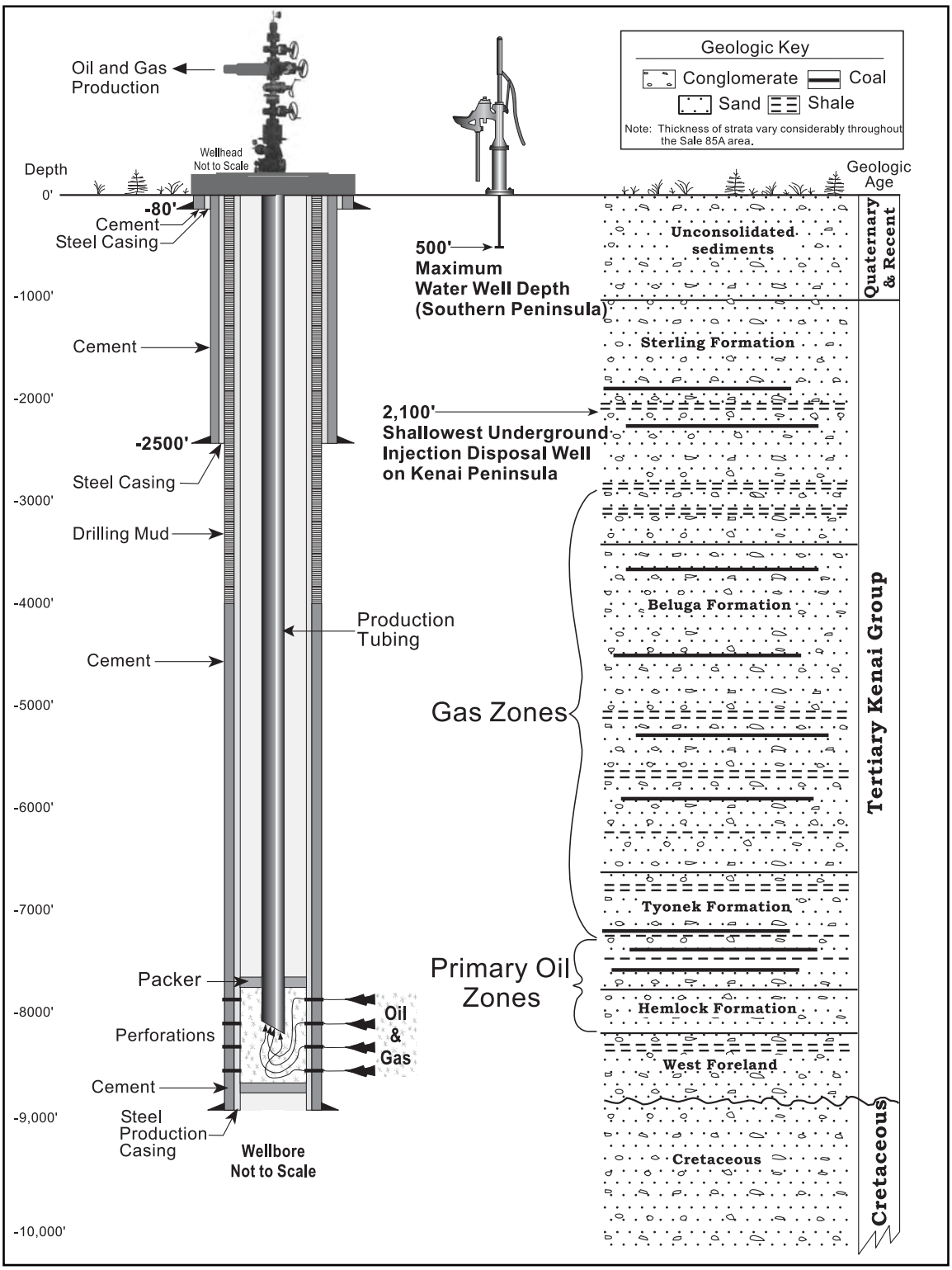


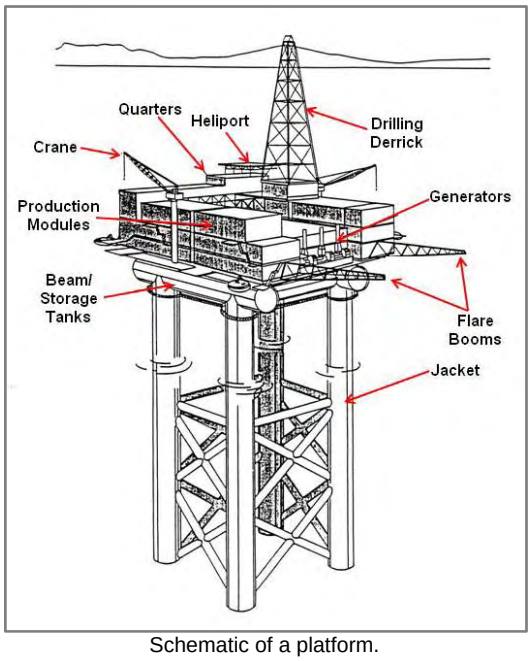
Figure 6.1. Schematic of a typical wellbore, Cook Inlet, Alaska.

there was unnecessary waste. In Cook Inlet, 1.07 bcf of gas was flared or vented during 2004, a decrease of 11.3% from 2003 (AOGCC 2004). For additional discussion about air quality regulations and the AOGCC, see Chapter 7, Sections B1, D, and F1.

The AOGCC may issue Conservation Orders (pool rules) to grant exceptions to regulations conditioned on prevention of waste, maximizing ultimate oil and gas recovery. Unless pool rules (oil or gas field rules governing well drilling, casing, and spacing that are designed to maximize recovery and minimize waste) have been adopted under 20 AAC 25.520, existing spacing rules stipulate that where oil has been discovered, not more than one well may be drilled to that pool on any governmental quarter section (20 AAC 25.055(a)). This would theoretically allow a maximum of four well sites per 640-acre section.

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

When the development area is offshore and not within reach of existing infrastructure, a new platform may be proposed. Existing platforms in Cook Inlet were constructed onshore, floated to the desired location, sunk, and driven in place. A Cook Inlet 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:



Schematic of a platform.

- Rigid platforms
  - Steel-jacket platform (piles; >1,000 feet water)
  - Concrete gravity platforms
  - Steel-caisson platform (tide and ice resistant; Cook Inlet)
- 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).

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. The oil is then piped to the local refinery at Nikiski or loaded onto tankers for shipment to outside refineries. 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. Onshore support facilities include a production facility to receive and treat the oil and gas for transportation to a refinery or other processing facilities, a supply base and vessel to provide the platform with cement, mud, water, food, and other necessary items, a supply vessel to bring the items to the platform, and a helicopter base. Helicopters carry crews to and from the 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. 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.

Gas for use in the Cook Inlet region along the gas pipeline distribution system is in short supply during the winter months of peak demand. When demand exceeds supply, gas delivery contracts specify that industrial use be curtailed, thus requiring plant operators to shut down facilities and output. Subsurface storage of gas increases reliability of gas delivery to electric utility companies, industrial users, and all residents who use gas in the Cook Inlet Basin.

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 and 20 AAC 25.055. 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 is 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.

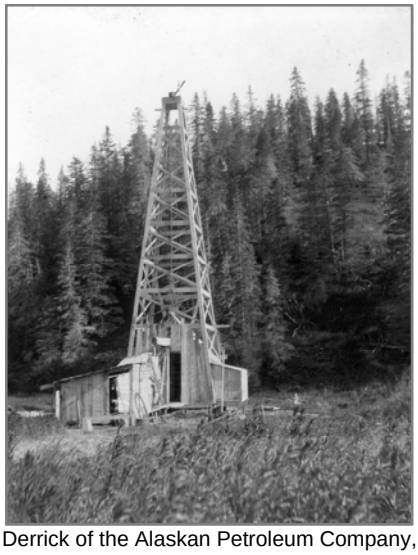
D. Oil and Gas Exploration, Development, and Production in Cook Inlet

The Cook Inlet Basin is a mature petroleum province. The area of gas and oil discoveries in the upper Cook Inlet Basin extends from the Kachemak Bay area north to the mouth of the Susitna River and includes fields in offshore Cook Inlet, the west shore of Cook Inlet and the western half of the Kenai Peninsula. The entire area covers approximately 4,400 square miles.

1. History of Oil and Gas in Cook Inlet

a. Prior to 1959

Exploration for oil in the Cook Inlet area began in the 1800s. Oil was reported on the west side of Cook Inlet in the vicinity of the Iniskin Peninsula by the Russians as early as 1853 (ADF&G 1985). In the early 1900s, Austin Lathrop drilled three wells on the west side of Cook Inlet. One was abandoned after a few hundred feet. The second well reached crude oil but encroaching water caused its abandonment. The third well was drilled but turned out to be unsuccessful (Berry 1973).



T. W. Stanton, USGS

Derrick of the Alaskan Petroleum Company, Oil Bay, Cook Inlet, 1904.

Drilling continued sporadically in the first half of the century with little success. The end of World War II brought increased settlement to the Kenai Peninsula and the development of a road system. This inspired oilmen to study Alaska's resources again. In 1955, Richfield Oil Corporation began exploration on the Kenai Peninsula in the Swanson River area. Oil was discovered on July 23, 1957, at a depth of 11,000 feet and flowed at a rate of about 900 barrels a day (Berry 1973)

Shortly after the Swanson River discovery, Standard Oil Company of California and Richfield formed a joint venture to explore for oil. Additional wells were drilled in the Swanson River area, and more leases were taken on both sides of Cook Inlet. Several other oil companies moved in to participate in drilling activities on the Kenai Peninsula (Berry 1973). By 1959, the state's competitive leasing process was instituted, and 187,000 bbls of crude oil were produced annually. In 1960, following further development of the Swanson River and Soldotna Creek units, annual production rose to 600,000 bbls.

b. 1959-1989

In October 1959, Union Oil Company of California and Ohio Oil Company made the first major gas discovery in the Cook Inlet area at their Kenai Unit No. 14 in the Kalifornsky Beach gas field near Kenai (Berry 1973). The three wells Union-Ohio drilled in 1959 had sufficient capacity to fulfill a twenty-year contract with Anchorage Natural Gas Corporation (Berry 1973).

Alaska State Library, ASL-Industry-Petroleum-CookInlet-05

"Trading Bay" oil drilling platform, owned by Marathon Oil Company and Union Oil, 1969.

In 1962, Pan American Petroleum Corporation discovered the first offshore oil in Cook Inlet. This led to extensive exploration throughout the Cook Inlet region in the 1960s and 1970s (Figure 6.2, Figure 6.3). At the peak of Cook Inlet's

development drilling in the late 1960s, there were 14 offshore production facilities in upper Cook Inlet. Shortly after, in 1970, annual oil production peaked at 83 million bbls (ADNR 2007). In the early 1980s, exploration was focused in the lower Cook Inlet Federal Outer Continental Shelf, Upper Cook Inlet, Kalgin Island, Fire Island, and the SRS structure. The fifteenth platform, Steelhead, was installed in 1986.

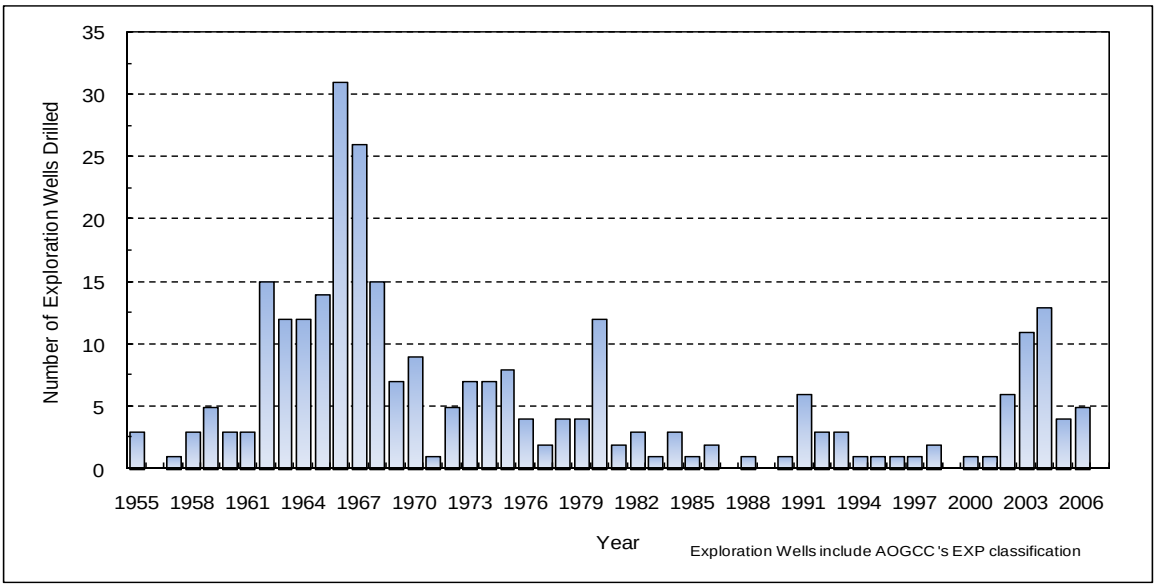


Figure 6.2. Exploration wells drilled in Cook Inlet, 1955-2007.

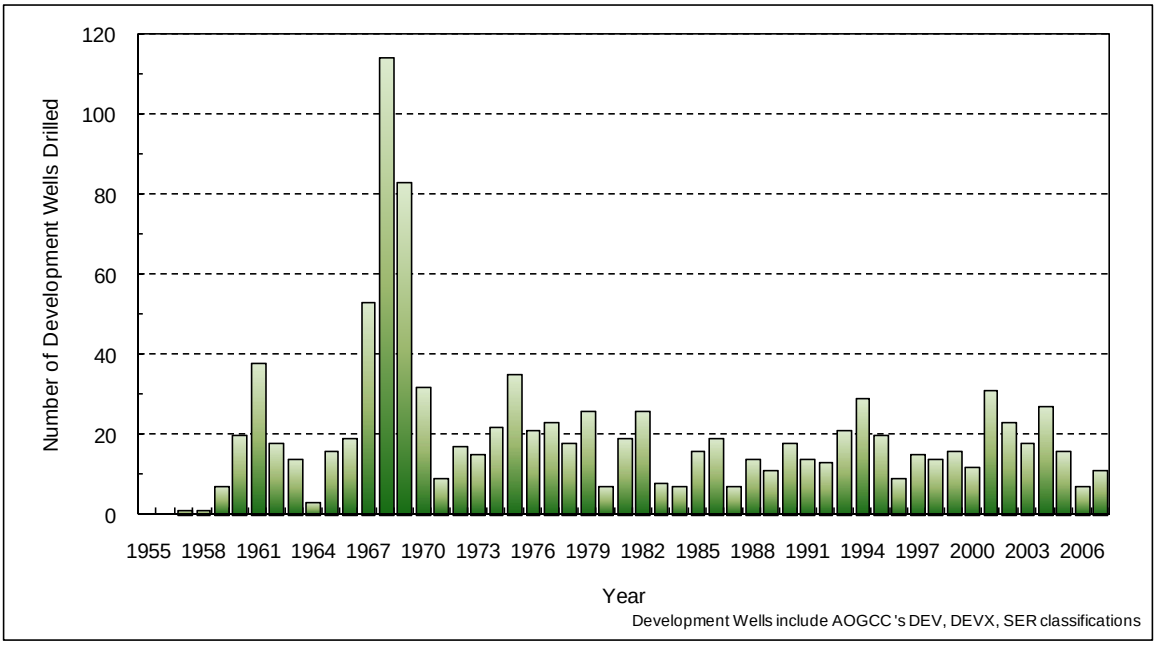


Figure 6.3. Development wells drilled in Cook Inlet, 1955-2007.

c. 1990-Present

In the 1990s and early 2000s, new oil developments and production began in the West MacArthur River Unit and in the Redoubt Unit respectively. Force Energy built the Osprey Platform in order to develop the Redoubt Field. Redevelopment efforts by XTO Energy, formally Cross Timbers Oil Company, doubled the oil reserves at Middle Ground Shoal (Cashman 2007). XTO Energy bought the field from Shell Oil and then developed the more difficult west flank of the field. In the early 1990s ARCO and Phillips Petroleum drilled multiple wells to evaluate the Sunfish sands (also known as Tyonek Deep). ADNR (2007) estimates the Tyonek Deep resource to be approximately 25 million barrels of oil and 30 Bcf of gas. Annual natural gas production also peaked in the late 1990s and early 2000s at 222 Bcf (ADNR 2007).

Coal bed methane (CBM) exploration in the Cook Inlet area started in 1994 with the Division of Oil and Gas drilling Alaska's first coal bed methane well, AK-94-CBM-1, near Wasilla. In 1997, Unocal formed the Pioneer Unit, located in the northern portion of the lease sale area, with a plan to explore for CBM. In 1998, the first commercial drilling for CBM occurred north of the lease sale area near Houston by Growth Resources Inc. of Australia. In 1999, Ocean Energy Resources Inc. acquired an interest in the Pioneer Unit and became the operator for the unit. Ocean drilled two CBM wells, one water injection well, and reentered one well. In 2001, Evergreen Resources, Inc. (Evergreen) purchased 100 percent working interest from both Ocean and Unocal, and then drilled and set casing on eight wells. In 2003, Evergreen announced that the two clusters of wells drilled by the company in the Pioneer Unit showed disappointing results. Between December 2003 and May 2004, Evergreen made a second attempt to understand the CBM potential in the area by completing a five hole mineral exploration core drilling program. On November 29, 2004 Evergreen Resources Alaska (Evergreen) was merged into Pioneer Natural Resources Alaska, Inc. In September, 2005, at Pioneer Natural Resources request, the DO&G approved the termination of the Pioneer Unit and accepted the surrender of all Pioneer Unit leases.

During the early 2000s, exploration and development drilling activity and 3-D seismic acquisition have increased in Cook Inlet. Companies are looking for reserves to replace declining fields. Modern 3-D seismic technology is being utilized to indentify previously unseen accumulations in existing fields; and smaller accumulations, once uneconomic, are now being explored. This opens a new class of exploration targets: stratigraphic traps.

D. Colley, DO&G

Cook Inlet oil production platform.

A significant amount of new activity has occurred in the southern portion of the lease sale area. Marathon and Chevron (formally Unocal) have drilled a number of exploratory and/or delineation wells in the Ninilchik, Nikolaevsk, and Deep Creek units. ConocoPhillips drilled a delineation well in the Cosmopolitan Unit; and more recently, Pioneer Natural Resources drilled a sidetrack to further delineate the Cosmopolitan Unit. Armstrong LLC is planning to drill a delineation well in the North Fork Unit in 2008. On the westside of Cook Inlet, Aurora Gas LLC drilled or sidetracked wells in the Three Mile Creek Unit, Moquawkie Unit, Lone Creek Unit, Nicolai Creek Unit, and Albert Kaloa Field. In addition to the areas mentioned above, Forest Oil's West Foreland Field, now owned and operated by Pacific Energy Resources LTD, had its first natural gas

production in 2001. Chevron, Marathon, Pioneer, Forest Oil, and ConocoPhillips have all recently shot 3-D seismic data over their leases. Both Chevron USA and ConocoPhillips have redevelopment programs in their onshore and offshore fields in Cook Inlet boost declining oil and gas production rates.

Gas storage in Cook Inlet was initiated in the early 2000s. Gas storage is used when the rate and timing of production of natural gas does not match the local demand. When production exceeds demand, the gas can be injected back into the ground to be extracted later when demand exceeds production. In 2001, the depleted gas reservoirs with good seals in the Tyonek formation at Swanson River Unit were the first reservoirs to be injected with natural gas. Gas injection into the Beluga formation at Pretty Creek started in 2005, and injection into Pool 6 of the Sterling formation at Kenai River Unit commenced in 2006.

The Cook Inlet region continues to be of interest to the petroleum industry. Annual oil production as of 2006 was 6 million bbls and annual gas production as of 2006 was 196 Bcf (ADNR 2007). As of the third quarter of 2007, the remaining resource in these fields consists of about 109 million barrels of oil and 1.5 trillion cubic feet of natural gas (DO&G 2008c). Existing developed and undeveloped accumulations in Cook Inlet are presented in Table 6.3.

2. Current Oil and Gas Infrastructure in Cook Inlet

Oil and gas infrastructure in the Cook Inlet area is well developed (Figure 6.4, Figure 6.5). Existing Cook Inlet oil production is handled through the Trading Bay production facility located on the west side of Cook Inlet and the Tesoro Refinery located at Nikiski. The Trading Bay facility pipelines crude oil production it receives to the Drift River Terminal. Almost all of the Drift River crude is transported to the oil refinery in Nikiski.

The Tesoro Refinery normally processes up to 55,000 bbl per day. Recent refinery production has been augmented by North Slope oil transported by tanker from Valdez. Almost all of the Tesoro refinery output is consumed within Alaska. A products pipeline links the Nikiski refinery with the Tesoro fuel depot located at the Port of Anchorage. A pipeline spur allows direct delivery into the airport’s tank farms. Tesoro's refined products include multigrades of gasoline, propane, Jet A, Diesel, No. 2 Diesel, JP4, and No. 6 fuel oil (MMS 1995). Asphalt produced at Nikiski is sold in Alaska. Nearly all of the remaining heavy oil, for which there is no local market, is exported to other states.

The ConocoPhillips-Marathon LNG plant was constructed in 1969 and produces 1.3 million tons of LNG annually. The LNG plant is operated by ConocoPhillips. The produced LNG is carried to Tokyo on two tankers, both operated by Marathon. The tankers travel a round trip of 6,600 nautical miles and make 16 to 19 trips per year. Each ship can carry 555,000 bbl of LNG. The LNG export license was extended for 10 years in 1999 and was most recently extended to 2011.

J. Rogers, ADOR

ConocoPhillips-Marathon LNG plant.

Natural gas produced from the Kenai Gas Field is transported by pipeline to Anchorage and Girdwood for domestic consumption. Gas produced from the Beluga River field is used on-site at the Beluga River power plant and is transported by pipeline to Anchorage via Wasilla and Palmer for domestic consumption (MMS 1995). Enstar Natural Gas Company has expanded its distribution system to encompass Palmer, Houston, and neighborhoods south of Soldotna.

In 1969, the Union Chemical plant started processing gas to produce ammonia and a similar quantity of urea pills and granules (for fertilizer). In 1978, the fertilizer plant was expanded; and then in 2000, Agrium purchased the Union Chemical plant. Some of the produced urea was used in Alaska; the rest was shipped to the U.S. West Coast in tankers and bulk freighters (MMS 1995). In September 2007, Agrium shut down its fertilizer plant due to gas shortages and increasing wholesale costs in Cook Inlet.

The lower portion of the lease sale area (south of Happy Valley) lacks the oil and gas infrastructure of upper Cook Inlet (Figure 6.5). Exploration and development would require construction of onshore drilling pads and possibly offshore platforms. A commercial discovery in this part of the lease sale area would require the construction of pipelines to connect with existing facilities. Some new roads may also be required.

Table 6.3. Estimated ultimate recovery and remaining oil and gas resources in Cook Inlet.

Field	Oil EUR. MMSTB	Oil Cum 10/2007, MMSTB	Oil Remaining Resources, MMSTB	Gas EUR, BCF	Gas Cum 10/2007, BCF	Gas Remaining Resources, BCF
McArthur River (TBU)*	655	627	29	1,452	1,329	123
Swanson River*	232	229	3	22	14	8
Middle Ground Shoal*	213	195	18	115	109	6
Granite Point*	165	145	20	142	130	11
Trading Bay	108	102	5	81	78	3
West McArthur River*	16	12	4	4	3	1
Beaver Creek*	7	6	1	218	195	23
ReDoubt Shoal	6	2	4	2	0	1
Tyonek Deep (Sunfish)			25	30		30
Kenai				2,458	2,332	126
North Cook Inlet				1,992	1,771	221
Beluga River				1,546	1,056	490
Under Development				389		389
Kenai Cannery Loop				186	159	28
Ninilchik				109	63	46
Ivan River				83	79	4
Kasilof				24	2	22
Deep Creek (Happy Valley)				16	9	7
Sterling				15	10	6
West Foreland				14	10	4
Lewis River				12	12	0
Moquawkie & Lone Creek				10	9	1
Pretty Creek				9	10	(0)
Nicolai Creek				7	4	2
West Fork				6	5	1
Stump Lake				6	6	0
Albert Kaloa				4	3	1
Three Mile Creek				2	1	0
Wolf Lake				1	1	0
Kustatan				0	0	0
North Fork				0	-	0
Totals	1,402	1,319	109	8,955	7,400	1,555

Source: DO&G 2008c.

Notes: EUR = estimated ultimate recovery; Cum = cumulative; MMSTB = million stock tank barrels; BCF = billion cubic ft.

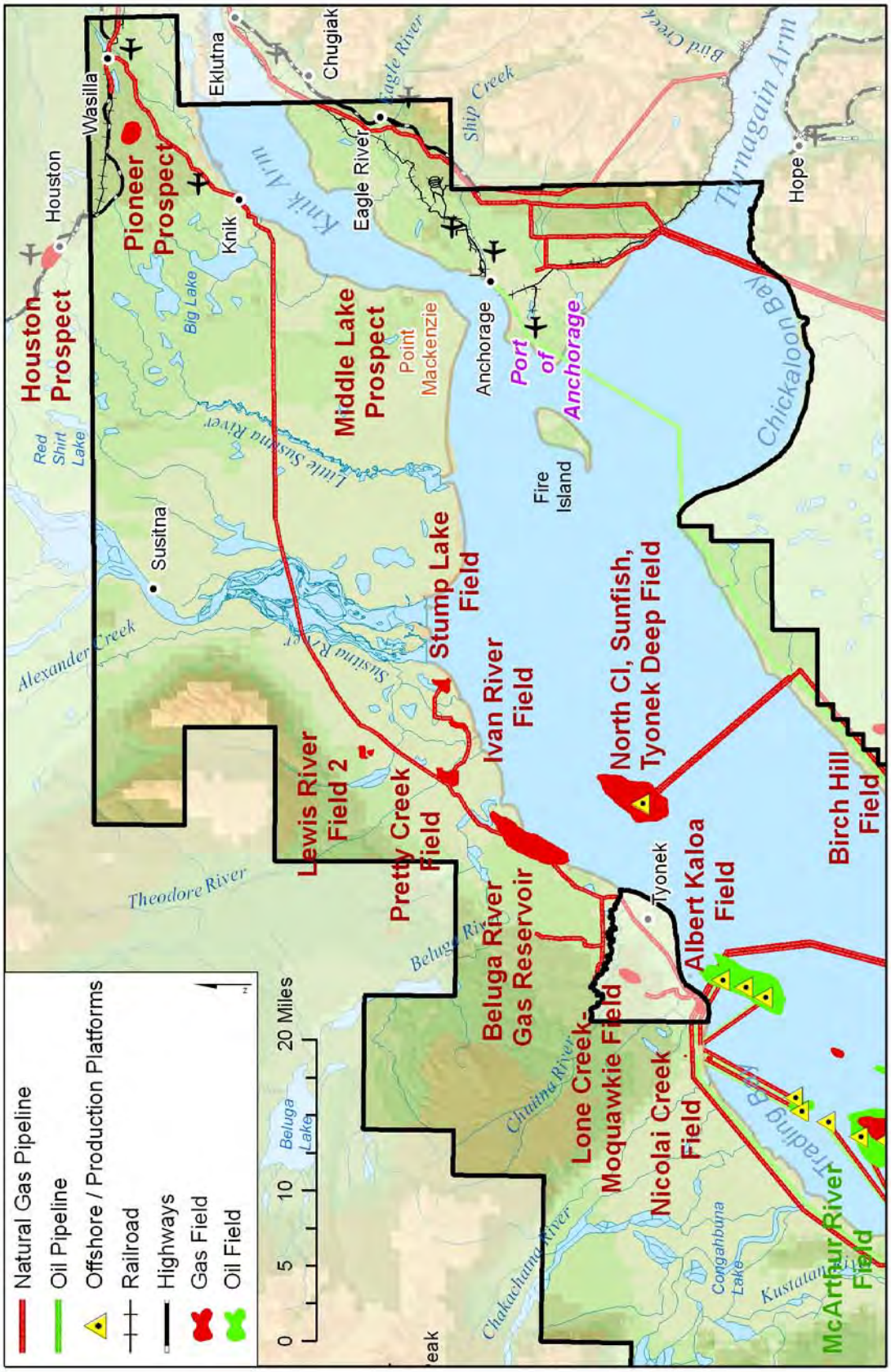


Figure 6.4. Oil and gas infrastructure in the upper Cook Inlet area.

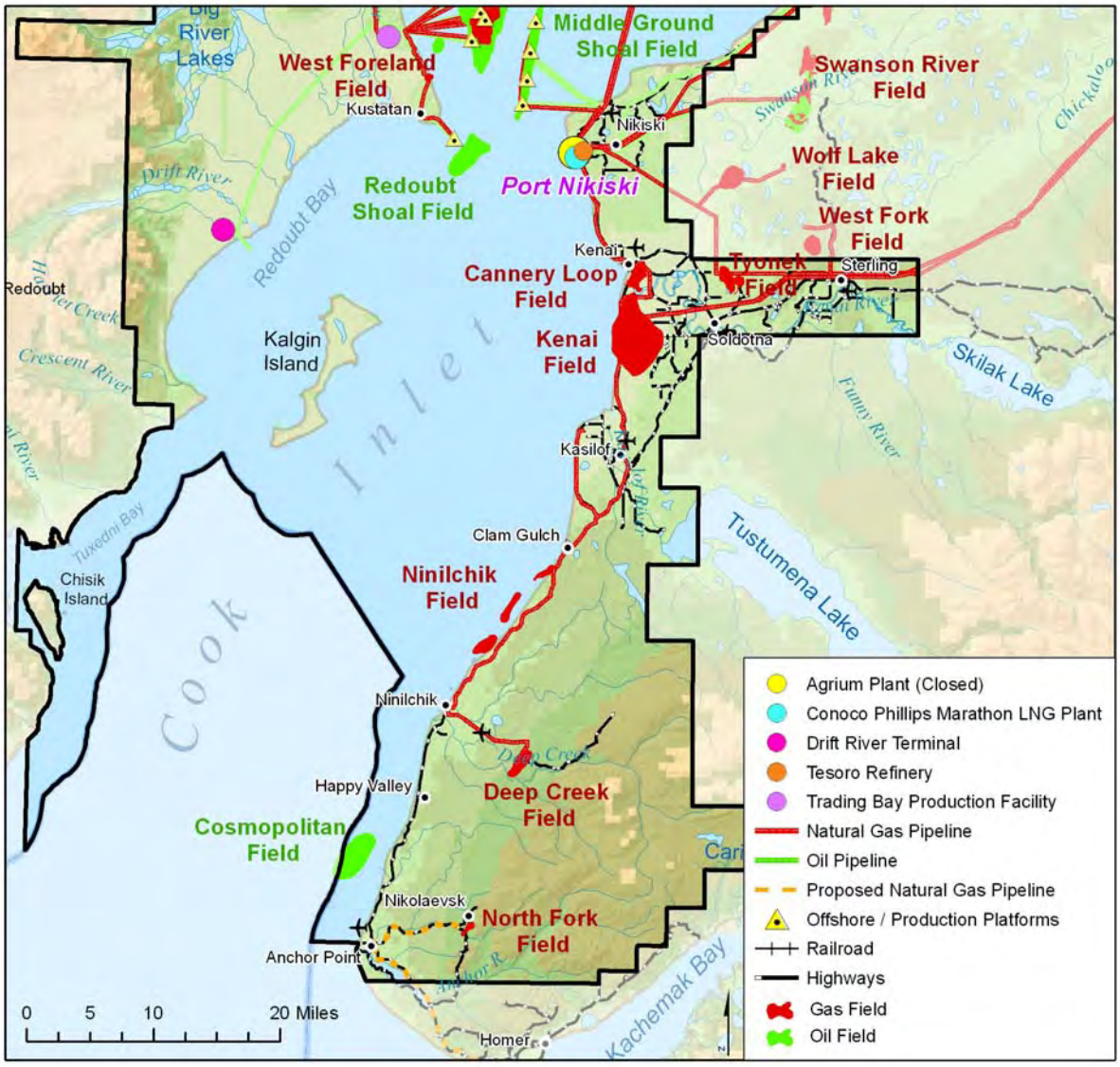


Figure 6.5. Oil and gas infrastructure in the lower Cook Inlet area.

3. Oil and Gas Leases in the Cook Inlet Area

Many factors contribute to the outcome of oil and gas lease sales in Alaska and Cook Inlet. 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.

Over 5.9 million acres of state land have been leased in 52 state oil and gas lease sales in the Cook Inlet region since 1959, not including lease sales from mixed areas (Table 6.4; Figure 6.6), generating up to $67.7 million in bonuses received by the state (Figure 6.7). Some of this acreage has been leased more than once because some leases had previously expired or were relinquished. As of December 30, 2008, about 1,186,331 acres were under lease, 510,705 acres offshore and 675,626 acres onshore (DO&G 2008a).

Federal oil and gas lease sales have also taken place in the Cook Inlet area. The Cook Inlet Outer Continental Shelf (OCS) area, encompassing about 2.5 million acres and 517 lease blocks, is assumed to hold about 140 million barrels of crude oil and 190 billion cubic feet of natural gas (MMS 2003). Additional lease sales have been proposed for 2009 and 2011 with net benefits estimated to be $1.38 billion (MMS 2006). The Cosmopolitan Unit, located in lower Cook Inlet, is a joint Federal OCS and state oil and gas unit. It comprises two federal and eight state leases, totaling 23,516 acres, and is in the exploration and development phases (MMS 2007). Additional oil and gas is estimated to occur on federal onshore lands, but 98 percent of those federal lands are inaccessible for development because of statutory and executive order restrictions (USDOI et al. 2008).

Table 6.4. Oil and gas lease sales in the Cook Inlet, 1959-2008.

Date	Sale	Description
12/10/59	1	Wide Bay; offshore Kenai to Ninilchik, Kachemak Bay
07/13/60	2	Kenai Pen., West Forelands, Nushagak Bay; offshore/uplands
12/07/60	3	Katalla, Kalifonsky Beach, Herendeen Bay; offshore Kodiak
01/25/61	4	Uplands Ninilchik
05/23/61	5	Tyonek, Controller Bay, Pavlov Bay; offshore/uplands
12/19/61	7	Icy, Yakutat & Kachemak Bays, So. Kenai Pen., N. Cook Inlet; offshore/uplands
04/24/62	8	Big Lake; uplands
07/11/62	9	Tyonek, W. Forelands, Knik Arm/Kalgin Is., Chisik Is., So. Kenai Pen., Wide Bay; offshore/uplands
05/08/63	10	Tyonek, Kenai; offshore/uplands
12/11/63	12	S. of Forelands, Knik & Turnagain Arms, Upper Cook Inlet, Kenai Pen., Tyonek to Katunu River; offshore/uplands
12/09/64	13	Fire Is., W. Forelands, Trinity Is., Prudhoe West; offshore/uplands
09/28/65	15	Fire Is. & N. Cook Inlet, Kalgin Is., Redoubt Bay, Knik, S. Kenai Pen.; offshore/uplands
07/19/66	16	Kenai Pen. & Knik, Middleton Is., Fire Is., Redoubt Bay, Kalgin Is., Iliamna Mt., N. Cook Inlet; offshore/uplands
11/22/66	17	Big Lake, Kenai; offshore/uplands
01/24/67	18	Katalla, Prudhoe; offshore/uplands
03/28/67	19	Lower Cook Inlet; offshore RULED INVALID ON 12/09/74
07/25/67	20	Big Lake, Knik, Iliamna Mt., Belukha, N. Cook Inlet, Kalgin Is., Ninilchik; offshore/uplands

-Continued-

Table 6.4. Page 2 of 2.

Date	Sale	Description
10/29/68	22	Big Lake, Knik, Belukha, West Forelands, Ninilchik, Kachemak & Kenai; uplands
05/12/71	24	Big Lake, Knik, Kenai, West Forelands; uplands
09/26/72	25	Big Lake, Knik, Belukha, North Cook Inlet; offshore/uplands
12/11/72	26	Cook Inlet (Between Forelands & Turnagain Arm); offshore/uplands
05/09/73	27	Tuxedni, Ninilchik, Kenai, Kalgin; offshore/uplands
12/13/73	28	Ninilchik, Kachemak Bay, Belukha; offshore/uplands
10/23/74	29	Kalgin & West Forelands, Chisik, Ninilchik, N. Cook Inlet, Turnagain, Big Lake; offshore/uplands
08/25/81	32	Lower Cook Inlet: Kenai Pen. and offshore
05/13/81	33	Upper Cook Inlet: Kenai Pen., Trading Bay, Beluga, Susitna R., Susitna Flats, uplands; offshore north of Salamatof
02/02/82	35	Lower Cook Inlet: Kenai Pen., Redoubt Cr. north to Drift R., uplands; offshore lower Cook Inlet
08/24/82	37A	Chakok River Exempt (Kenai Pen.); uplands
09/28/83	40	Upper Cook Inlet: Anchorage south to Homer; offshore/uplands
02/26/85	46A	Cook Inlet Exempt: Kenai Pen., Susitna R., Pt. MacKenzie, uplands; upper Cook Inlet
06/24/86	49	Cook Inlet: Kalgin Is., Kahiltna, Yentna, Skwentna rivers, Alexander Cr.; offshore/uplands
01/29/91	67A	Cook Inlet Exempt: Anch., lower Susitna Valley, Redoubt & Trading Bay, Kenai Pen., uplands; upper inlet, offshore
09/24/91	74A	Cook Inlet: Nikishka to Ninilchik, Drift R., West Forelands, uplands; Kalgin Is. north to Kenai Pen., offshore
01/26/93	76	Cook Inlet: Big Lake to Salamatof; onshore/offshore
01/26/93	67A-W	Cook Inlet Reoffer: Nancy Lake to West Forelands; onshore/offshore
10/31/94	78	Cook Inlet: Susitna R. to Stariski Cr.; onshore/offshore
11/14/95	67A-W2	Cook Inlet Reoffer: Trading Bay and Susitna R., onshore/offshore
11/14/95	74W	Cook Inlet Reoffer: Onshore/offshore, mouth of Kasilof R.
11/14/95	76W	Cook Inlet Reoffer: Onshore between Tyonek and Palmer, Knik Arm
11/14/95	78W	Cook Inlet Reoffer: Forelands to Little Susitna R, Kasilof R. to Stariski Pt., onshore/offshore
12/18/96	85A	Cook Inlet Exempt: Anchor Pt. and Tuxedni Bay to Turnagain Arm, Beluga R. offshore/onshore
02/24/98	85A-W	Cook Inlet Reoffer: Onshore/offshore; Tyonek to Tuxedni Bay and Chickaloon Bay to Ninilchik
Beginning of areawide lease sales		
04/21/99	Cook Inlet Areawide 1999	State acreage between Anchor Pt. and Houston
08/16/00	Cook Inlet Areawide 2000	State acreage between Anchor Pt. and Houston
05/16/01	Cook Inlet Areawide 2001	State acreage between Anchor Pt. and Houston
05/01/02	Cook Inlet Areawide 2002	State acreage between Anchor Pt. and Houston
05/07/03	Cook Inlet Areawide 2003	State acreage between Anchor Pt. and Houston
05/19/04	Cook Inlet Areawide 2004	State acreage between Anchor Pt. and Houston
05/18/05	Cook Inlet Areawide 2005	State acreage between Anchor Pt. and Houston
05/24/06	Cook Inlet Areawide 2006	State acreage between Anchor Pt. and Houston
05/23/07	Cook Inlet Areawide 2007	State acreage between Anchor Pt. and Houston
05/21/08	Cook Inlet Areawide 2008	State acreage between Anchor Pt. and Houston

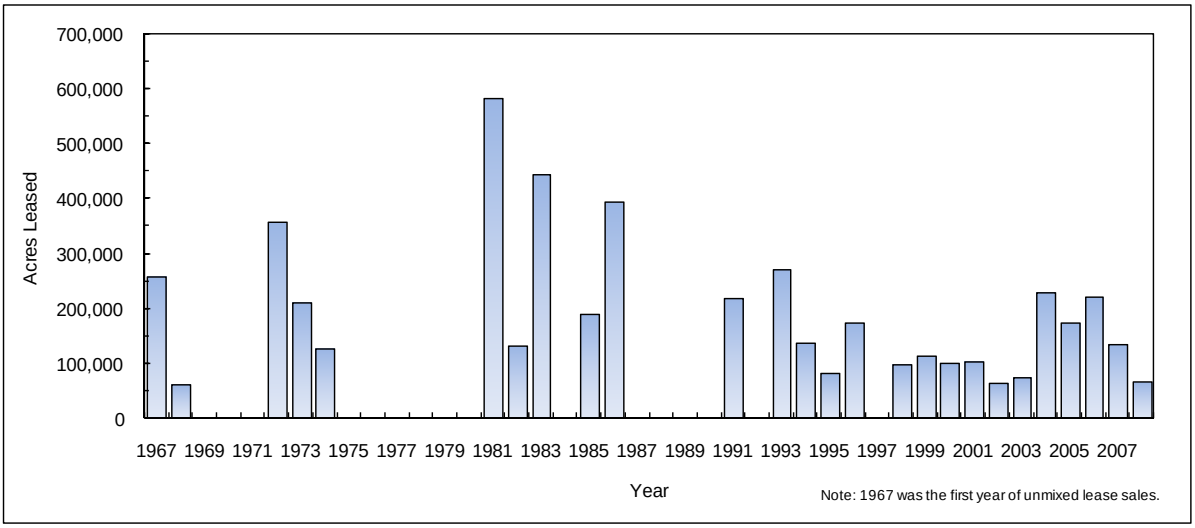


Figure 6.6. Acres leased in Cook Inlet state oil and gas lease sales, 1967-2008.

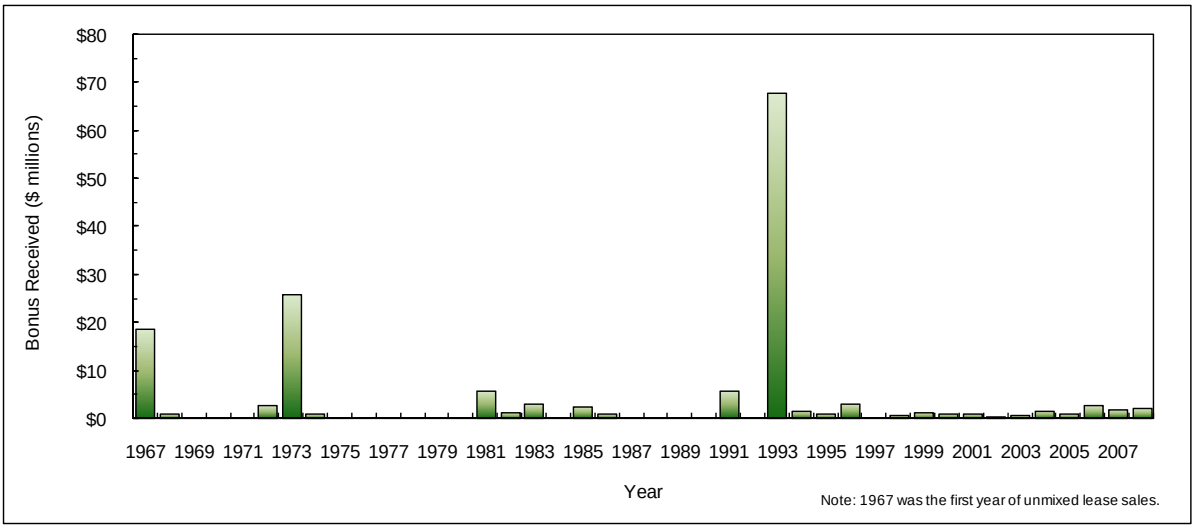


Figure 6.7. Bonuses received in state oil and gas lease sales in Cook Inlet, 1967-2008.

E. Likely Methods of Oil and Gas Transportation in Cook Inlet

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.

A discussion of specific transportation alternatives for oil from the lease sale area is not possible at this time because 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: 1) pipelines; 2) marine terminals; and 3) tank vessels. Oil and gas produced in the lease sale area would most likely be transported by a combination of these depending on the type, size, and location of the discovery.

The Cook Inlet basin has produced crude oil and natural gas since the 1960s. As a result, the basin has a well-developed infrastructure for transporting petroleum at least in the upper Cook Inlet area. The lower Cook Inlet area (south of Ninilchik) lacks the oil and gas infrastructure of upper Cook Inlet (KPB 2005). From 1997 to 2006, over 2,115 billion cubic feet of natural gas and almost 100 million barrels of crude oil have been produced in the region (DO&G 2007).

The possible modes 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.

1. Pipelines

Offshore and onshore pipelines have operated in the Cook Inlet area since the 1960s. There are approximately 221 miles of undersea pipelines, 78 miles of oil pipelines, and 149 miles of gas pipelines (MMS 2003).

B. Havelock, DO&G

Oil transit lines, Nikiski.

Since original construction and startup of operations of the pipelines in the Cook Inlet area, the Pipeline Safety Improvement Act of 2002 was signed into law (Pipeline Safety Bill H.R. 3609). In December 2003, the Office of Pipeline Safety issued a final rule requiring natural gas pipeline operators to develop integrity management programs for gas transmission pipelines located where a leak or rupture could do the most harm; that is, could impact high-consequence areas (HCAs).

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 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 have the potential to eventually weaken the pipe, or even cause it to fail, are identified early on 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.

Integrity management inspections are comprehensive, and a team of inspectors is often used to conduct the inspection. For operators with significant mileage, integrity management inspections generally require two weeks (PHMSA 2008).

Elevated pipelines onshore are relatively easy to maintain and visually inspect for leaks but they can restrict wildlife movements unless provisions are made to allow for their unimpeded passage. However, because onshore pipelines in the Cook Inlet area are usually buried and the ground reseeded, they do not pose an obstacle to wildlife or result in scenic degradation.

An offshore pipeline moves oil from the Middle Ground Shoal field, located in the middle of Cook Inlet, to the Nikiski marine terminal on the east side of Cook Inlet. The Cook Inlet Pipe Line Company transports crude oil via an offshore pipeline system from the Trading Bay, McArthur River, and Granite Point fields to the Drift River marine terminal on the west side of Cook Inlet (MMS 2003).

Subsea pipelines are the most likely system for transporting oil or gas from new offshore development areas to loading or processing facilities. Pipelines have transported petroleum liquids under Cook Inlet waters since the 1960s. 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 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 F2b below for further information on leak detection methods.

2. Tankers

Tanker traffic in Cook Inlet currently carries oil produced from the west side of Cook Inlet to the east side to be refined. Tankers then deliver refined petroleum products from the Nikiski complex to other parts of Alaska. Tankers calling at the Nikiski terminals and refineries transfer about 22 million barrels of crude and refined (non-persistent) oil each year and transfer about 4.8 million barrels of crude from the Drift River Terminal to Nikiski each year.

Courtesy Polar Tankers, Inc.

Example of a tanker used to transport oil.

The Kenai Liquefaction Plant includes facilities for liquefying, storing, and loading natural gas. The gas is processed to remove impurities such as water or carbon dioxide, then liquefied by lowering its temperature to -259°. During this process the gas shrinks to 1/600th of its original volume. The liquefied natural gas (LNG) is then transferred to three heavily insulated, 225,000-barrel (bbl) storage tanks. While in storage, some of the LNG “boils off.” This maintains the remaining LNG at its liquid temperature and provides fuel for the plant’s large refrigeration unit. Finally, the LNG is loaded onto tankers from transport to Japan. (Kenai LNG 2007). Every 10-20 days, the Phillips-Marathon LNG facility loads 80,000 cubic meters of LNG onto tankers for shipment to Japan and delivers refined petroleum products from its Nikiski complex to other parts of Alaska and the Pacific Rim. Refined oil from the Tesoro Refinery is also put onto tankers at the Nikiski Terminal Wharf (MMS 2003).

3. Marine Terminals

The marine crude oil terminals in Cook Inlet include storage facilities and offshore loading platforms. The Nikiski complex has been in operation since 1963 and includes the Phillips/Marathon LNG plant, and Tesoro’s refinery. The complex receives, stores, and pumps crude oil to the Tesoro refinery. The

Drift River marine terminal started operating in 1967. It receives Cook Inlet crude oil via pipeline from production areas on the west side of Cook Inlet and stores the oil until tankers move it across Cook Inlet to the Tesoro refinery. Currently, no Cook Inlet crude oil is shipped out of the state.

4. 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 in the state 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 best interest finding to avoid, minimize, and mitigate potential negative effects of transporting oil and gas (see Chapter 9). 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

1. Oil Spill History and Risk

The risk of a spill exists any time crude oil or petroleum products are handled. Oil spills associated with the exploration, development, production, storage, and transportation of crude oil may occur from well blowouts or pipeline or tanker accidents. Petroleum activities may also generate chronic low volume spills involving fuels and other petroleum products associated with normal operation of drilling rigs, vessels, and other facilities for gathering, processing, loading, and storing of crude oil. Spills may also be associated with the transportation of refined products to provide fuel for generators, marine vessels, and other vehicles used in exploration and development activities. A worst case oil discharge from an exploration facility, production facility, pipeline, or storage facility is restricted by the maximum tank or vessel storage capacity or by a well’s ability to produce oil.

Since 1999 there have been 18 crude oil spills of 100 gallons or more from pipelines, platforms, onshore production facilities, storage facilities, and marine tankers in the Cook Inlet area. Six of these were more than 500 gallons (ADEC 2008c).

On January 6, 1999, a leak was discovered in an eight-inch crude oil pipeline buried forty inches below the surface in the Swanson River Oil Field in the Kenai National Wildlife Refuge. The responsible party, Unocal, estimated that 60 barrels (2,520 gallons) of crude oil and 1,300 barrels (54,600 gallons) of produced water spilled. Cleanup consisted of removing contaminated snow and transporting it to Unocal's solid waste facility (ADEC 1999).

On February 6, 1999 the *Chesapeake Trader* spilled 420 gallons of crude oil into Cook Inlet between Nikiski and Homer. 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 March 1989 *Exxon Valdez* oil spill, the largest recorded spill 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 8.

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 clean up 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 section.

a. Exploration and Production

Spills related to petroleum exploration and production must be distinguished from those related to transportation because the phases have different risk factors and spill histories. Exploration and production facilities in the lease sale area may include onshore gravel pads; drill rigs; pipelines; and facilities for gathering, processing, storing, and moving oil. These facilities are discussed below. Spills occurring at these facilities 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.

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.

b. Pipelines

Both state and federal agencies have oversight of pipelines in Alaska. State agencies include the Petroleum Systems Integrity Office (PSIO) and DO&G within DNR; the State Pipeline Coordinator's Office; and DEC. Federal agencies include the Pipeline and Hazardous Materials Safety Administration (PHMSA) within the U.S. Department of Transportation; and MMS.

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 five 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 that occurred in 2006 made the oil and gas industry, local, state, and federal regulators, and the general public, acutely aware of potentially widespread pipeline corrosion issues on the North Slope. 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 has promulgated new regulations regarding education, preparation for spills, and spill response; these regulations have been approved and went into effect in December 2006.

c. Marine Terminals and Tanker Vessels

Both the Nikiski and Drift River terminal facilities generally have good safety records. Volcanic activity associated with Mt. Redoubt in 1989 and 1990 caused the temporary closure of the Drift River facility between January and mid-June 1990 due to the threat of flooding. By August 1990, following construction of new protective dikes, the terminal resumed normal operations.

In March 1990, approximately 2,300 bbl (96,600 gal) were spilled at Drift River when a valve on tank number 3 was accidentally left open. The entire spill was contained within protective dikes and none was released into the water. Nearly all of the spilled oil was cleaned up by returning it to the storage tank or by direct treatment. In December 1990, another incident occurred when ice carried by swift currents forced the UNOCAL tanker *Coast Range* away from the dock at the Drift River facility. This caused a spill of approximately 15 bbl (630 gal) of oil located in the pipes between the dock and the ship. Cleanup workers used absorbents to clean up the spill because booms and skimmers were ineffective in the heavy ice (ADN 1990). ADEC estimates that 30 percent of the spill was cleaned up and 10-20 percent evaporated. This left approximately 7.5 bbl (315 gal) unrecovered.

On December 5, 1995, a spill occurred at the Tesoro tank farm in Nikiski. Crude oil overflowed when a high-fill-level alarm failed during a tank-to-tank transfer. Some of the oil escaped the secondary containment berm around the tank and reached Cook Inlet. The oil moved north in the water and into the rip currents. Cook Inlet Spill Prevention and Response, Inc. (CISPRI) responded and recovered some of the oil. The remainder disappeared within three days (ADEC 1995). Approximately 2,500 to 2,900 gallons of crude oil were released, and ADEC fined Tesoro (CISPRI 1998).

A tanker accident can result in the release of large quantities of oil in a short time, causing severe environmental damage. An oil spill in a marine water setting is also much more difficult to contain than one on land because ocean currents and tidal actions carry the oil over a much larger area. An example of the potential magnitude of a tanker spill is the March 1989 *Exxon Valdez* oil spill discussed above.

The Oil Pollution Act of 1990 (OPA), which was enacted after the *Exxon Valdez* oil spill, requires that all tank vessels greater than 5,000 gross tons that are constructed or that undergo major conversions under contracts awarded after June 30, 1990, must have double hulls to operate in U. S. navigable waters. Of the 51 major oil spills, all 24 major spills from tank vessels (tankers and tank barges) involved single-hull vessels (GAO 2007). Single-hulled tankers must be phased out by 2015. Double-hulled tankers currently transport the majority of oil in Cook Inlet (CIRCAC 2002). In 2008, a 6,700 horsepower tug funded by Tesoro was stationed in Cook Inlet to assist oil tankers docking at Nikisiki (Stuart 2008).

d. Alaska Risk Assessment of Oil and Gas Infrastructure

In May 2007, the Alaska Risk Assessment (ARA) project was launched. The purpose of this three-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 2008a).

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 2008a).

2. 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 9, and some are discussed at the beginning of this section. Prevention measures are also described in the oil discharge prevention and contingency plans that the industry must prepare prior to beginning operations. Thorough training, well-maintained equipment, and routine surveillance are important components of oil spill prevention.

Technical design of pipelines and other facilities reduces the chance of oil spills. As discussed in Chapter 3, Section G8, 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;
- Waterbody 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).

J. Easton, DO&G

Example of a blowout prevention stack at Jacob's Ladder exploration well (North Slope).

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 drillpipe. 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

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 currently uses the volume balancing method, which involves comparing input volume to output volume.

B. Havelock, DO&G

Valve station, Kenai-Kachemak Pipeline.

The technology for monitoring pipelines is continually improving. Leak detection methods include acoustic monitoring, pressure point analysis, and combinations of some or all of the different methods (Yoon et al. 1988). 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. This technology can minimize spills from both new and old pipelines (Yoon and Mensik 1988).

A similar technology for detecting leaks in oil and gas pipelines is termed Pressure Point Analysis (PPA). The method uses measured 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 which 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. Since 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 gases to enter the inner tube. A protective layer of braided plastic strips forms the outer layer. The tube is filled with fresh air, and the air is evacuated through a leak detector at regular intervals. If a leak occurs, hydrocarbon gases associated with the leak enter the tube and are carried to the gas detector. The system is totally computer controlled, self-checking and re-setting. Background gases are calibrated at setup and checked regularly. The system will pick up previous contamination and organic decomposition. The location of the leak is determined by monitoring the time that leaked gas arrives at the detection device.

The 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

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 pipeline operators 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.

The Forward Looking InfraRed (FLIR) pipeline monitoring program assists in detecting pipeline leaks and corrosion in the Kuparuk oil field. Infrared sensors have the ability to sense heat differentials. A leak shows up as a "hot spot" in an FLIR video. 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. 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. Various agencies involved in the process are able to see and verify the results of the cleanup process (ARCO 1998).

3. Oil Spill Response

a. Incident Command System

An Incident Command System (ICS) response is activated 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. Since 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 2006).

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 Federal On-Scene Coordinator and the State On-Scene Coordinator decide that the Responsible Party is not doing an adequate job of response (ADEC 2006).

b. Response Teams

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. 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 2006).

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. 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 from 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; skimmer use; detection and tracking of oil; oil recovery on lakes; river booming; radio communications; ATV, snowmobile, and four-wheeler operations; oil discharge, prevention, and contingency plan review; communication equipment operations; Arctic survival; oil spill burning operations; pipeline leak plugging; and spill volume estimations.

d. Response Organizations

Cook Inlet Spill Prevention and Response, Inc. (CISPRI) is a major spill response organization in Cook Inlet. The non-profit corporation was formed in October 1990 to provide personnel and oil spill equipment to respond to any kind of oil spill at the request of a member company. Operators of various facilities contract with CISPRI for response activities. The U.S. Coast Guard designated CISPRI a Tier 3 Oil Spill Removal Organization (OSRO), which is the highest level of designation and is based on spill containment and removal requirements for an offshore/ocean response. CISPRI is registered with the State of Alaska as a Primary Response Action Contractor and as a Nontank Vessel Cleanup Contractor. No single entity owns CISPRI. It is a cooperative funded by oil industry companies with interests in Cook Inlet. CISPRI is governed by a board of directors comprised of members elected from the oil industry companies, and the following from the public sector: U.S. Coast Guard, ADEC, the Kenai Peninsula Borough, and the Municipality of Anchorage. CISPRI's response area extends from Palmer to the Barren Islands and into the Gulf of Alaska (CISPRI 2008).

CISPRI's major assets include:

- Over 82,500 feet of various sizes of oil containment boom, including fire boom;
- Over 98,304 bbl/day of spill removal equipment (skimming equipment);
- Over 87,000 barrels of on-water storage capacity;
- Pumps, powerpacks, and support equipment specifically designed to augment spill response;
- Extensive communication network established throughout Cook Inlet;
- 20 dedicated response vessels ranging from 16' to 204' in length;
- Contracts with over 120 fishing and commercial vessels to support spill response efforts;
- Dedicated warehouse/office/command center to support daily operations and emergency spill response efforts;
- Specialized equipment to conduct alternative response measures, including application of oil dispersants and conducting in-situ burning operations;
- Dedicated facilities and support equipment for the capture, cleaning, and rehabilitation of oiled birds and sea otters.

CISPRI's response center is located at Mile 26.5 North Spur Road near Nikiski, Alaska. In the event of a spill, the location serves as the emergency operations center for all federal, state, and industry personnel. CISPRI's response actions include:

- **Notification and Initiation of Response**: The CISPRI manager receives notification from the responsible party or the U.S. Coast Guard and in turn notifies the Operations Manager. The Operations Manager initiates a group call-out for CISPRI technicians to respond within one hour. All CISPRI employees carry cell phones for after-hours notification. In the event of a non-member or mystery spill, the U.S. Coast Guard calls the CISPRI manager and initiates a response.

- **Organization and Call-out**: CISPRI personnel assemble at the designated staging area and begin response actions appropriate to the problem. Personnel are dispatched to the location of the spill for site assessment. In an offshore spill, response personnel would activate the *Perseverance*, CISPRI's spill response vessel.
- **Documentation**: All CISPRI personnel are required to document their activities during an oil spill. The documentation covers actions taken, when and by whom directions were given, and where and by whom the action was performed. The Operations Section staff log who directed the action, what personnel and/or equipment was deployed, when it was deployed, and how long the action is expected to last.

CISPRI developed a technical manual that incorporates its emergency action plan, reporting and notification procedures, safety plan, communications, deployment strategies, response strategies, non-mechanical response options, description of its vessel, command system, realistic maximum response operating limitations, logistical support, response equipment, contractor information, training plans, and protection of environmentally sensitive areas. The technical manual is a part of the contingency plans prepared by each of CISPRI's member companies (CISPRI 1997).

Other response organizations may operate in the Cook Inlet area if they meet U.S. Coast Guard and ADEC standards. Each organization may operate a little differently, but the objective is the same – to minimize the impact of an oil spill. Some operators maintain mutual aid agreements with other operators so that if the spill exceeds their individual capabilities, they may access other resources.

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, sorbants, in-situ burning, and dispersants application machinery. The responsible party and its contractors usually perform response activities with assistance and monitoring by federal and state agencies.

The history of crude oil spills in Cook Inlet and the low to moderate potential for discovering new reserves indicates that there is low to moderate probability of a major spill occurring as a result of the areawide lease sale. However, the environment of Cook Inlet can present extremes that might make it difficult to effectively contain and cleanup a major spill. The effects on the sensitive environments of Cook Inlet could be severe if they were unmitigated.

Spill responders in Cook Inlet face a challenging task. Strong currents and large tides in Cook Inlet move oil rapidly. Winter ice, darkness, and severe weather can endanger responders and interfere with the recovery of spilled oil. Thick ice could block access to spilled oil, although broken ice might actually help capture floating oil. Darkness increases the difficulty in observing oil on water. Severe weather could put responders at risk. Chapter 3 contains a description of the Cook Inlet environment.

e. Geographic Response Strategies

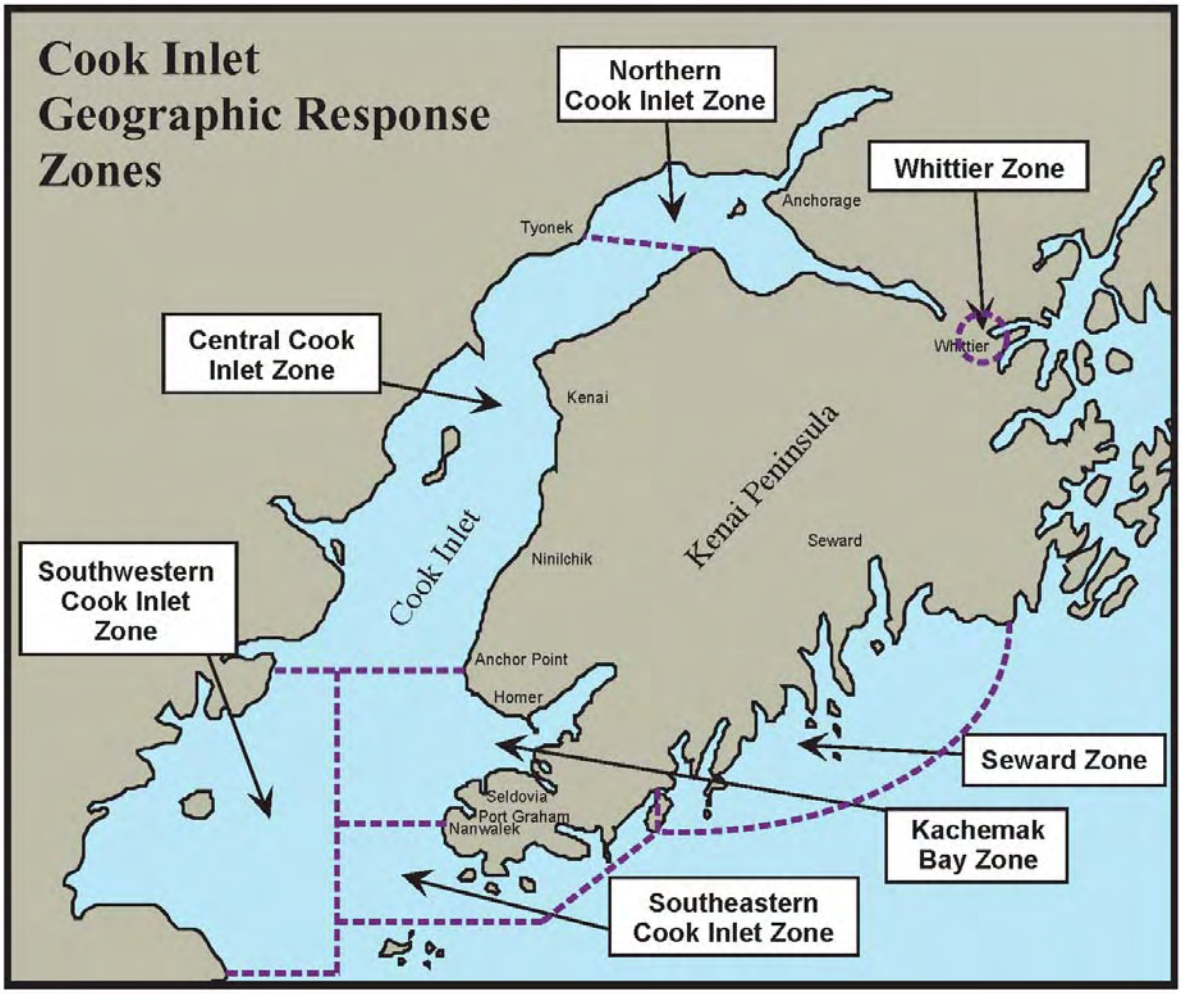
Geographic Response Strategies (GRS) are oil spill response plans that protect specific sensitive areas from the effects of oil following a spill (ADEC 2008b). The purpose of these map-based strategies is to

save time during the critical first few hours after an oil spill. They provide the location of sensitive areas and where to deploy oil spill protection equipment.

A workgroup, composed of local spill response experts and the state and federal agencies who make up the Cook Inlet Regional Citizen's Advisory Council, developed the GRS with public input (ADEC 2008b). Sites were selected based on environmental sensitivity, risk of being impacted from a water borne spill, and feasibility of successfully protecting the site with existing technology. Strategies focus on minimizing environmental damage, utilizing as small a footprint as possible to support the response operations, and selecting sites for equipment deployment that will not cause more damage than the spilled oil.

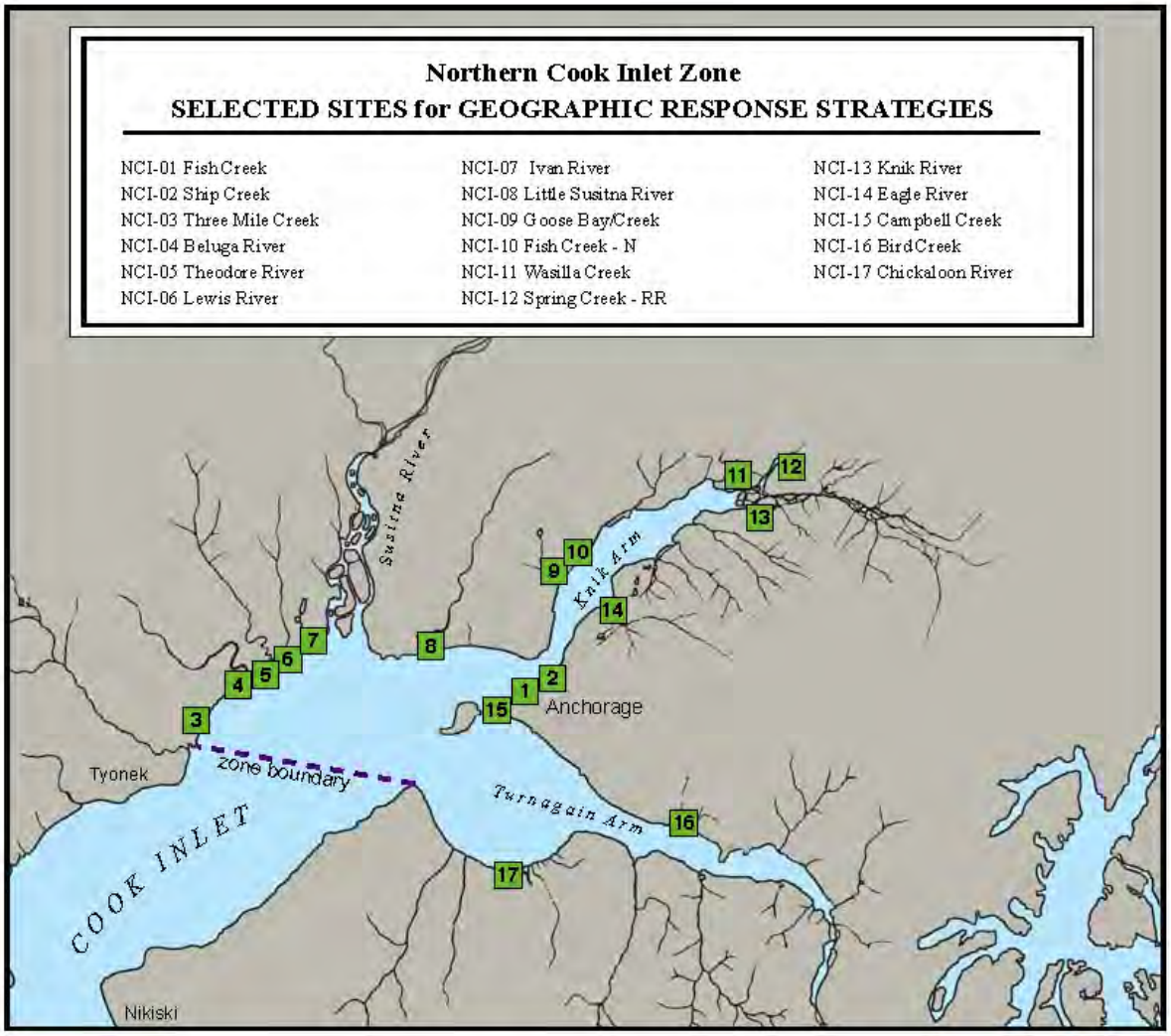
Within the Cook Inlet area, five geographic response zones fall within or adjacent to the lease sale area (Figure 6.8): northern Cook Inlet (from the Chuitna River on the west side of Cook Inlet to Point Possession on the east and north to the Matanuska River); central Cook Inlet (from Anchor Point north to just north of Tyonek including both the east and west coastlines of Cook Inlet); southwestern Cook Inlet (from Cape Douglas north to Sea Otter Point at the southern entrance to Chinitna Bay); Kachemak Bay (from Point Bede, just south of Nanwalek, north to Anchor Point at the northern entrance to Kachemak Bay); and southeastern Cook Inlet (from south of Point Bede northeast to Division Island at the northern entrance to Nuka Passage).

Within the northern Cook Inlet response zone, response strategies have been developed for 17 sites (Figure 6.9); 22 sites for central Cook Inlet (Figure 6.10); 18 sites for southwest Cook Inlet (Figure 6.11); 21 sites for Kachemak Bay (Figure 6.12); and 22 sites for southeast Cook Inlet (Figure 6.13). An example of a GRS for a specific site (the Kasilof River) is provided in Figure 6.14.



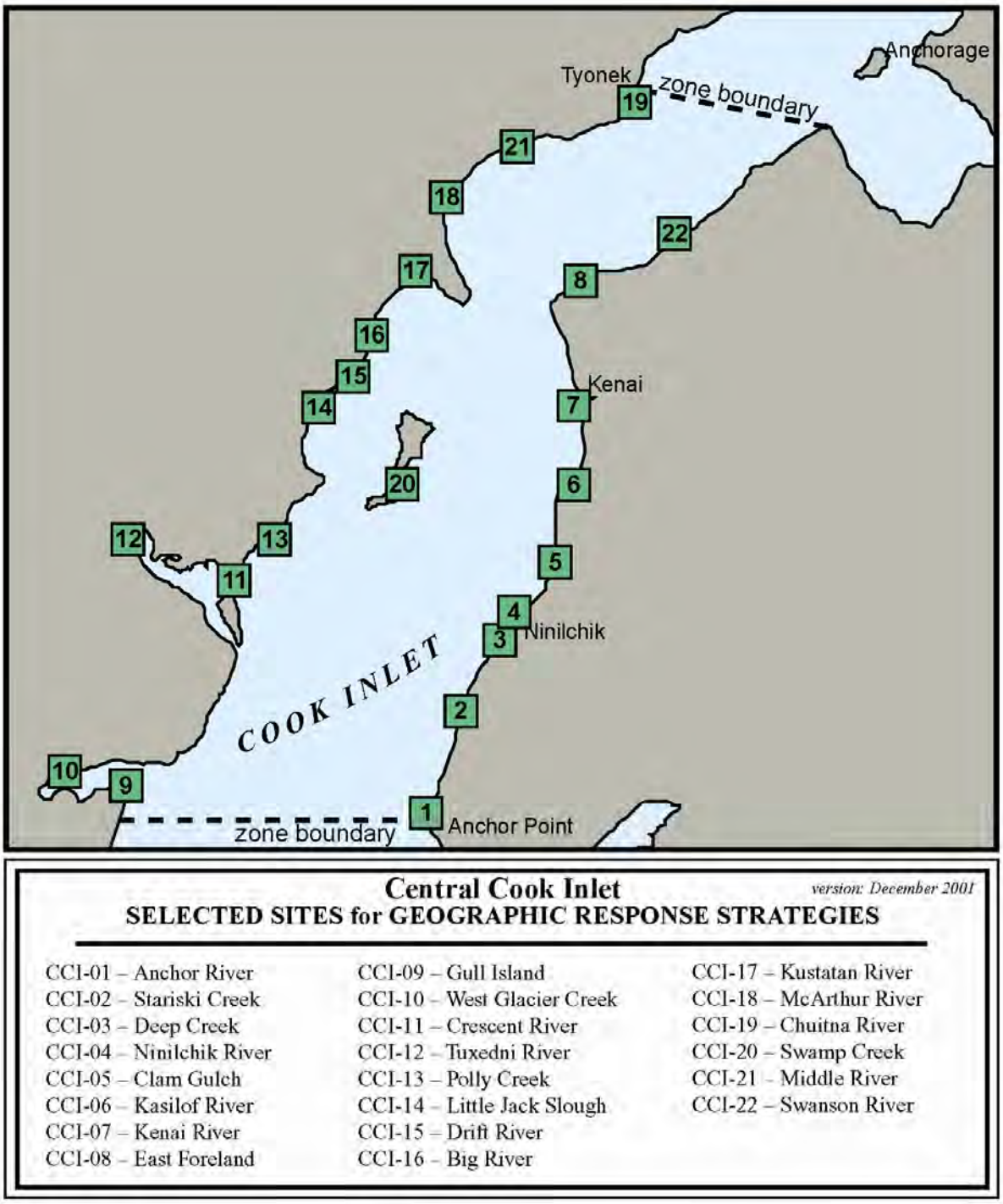
Source: ADEC 2008b.

Figure 6.8. Geographic Response Zones in Cook Inlet.



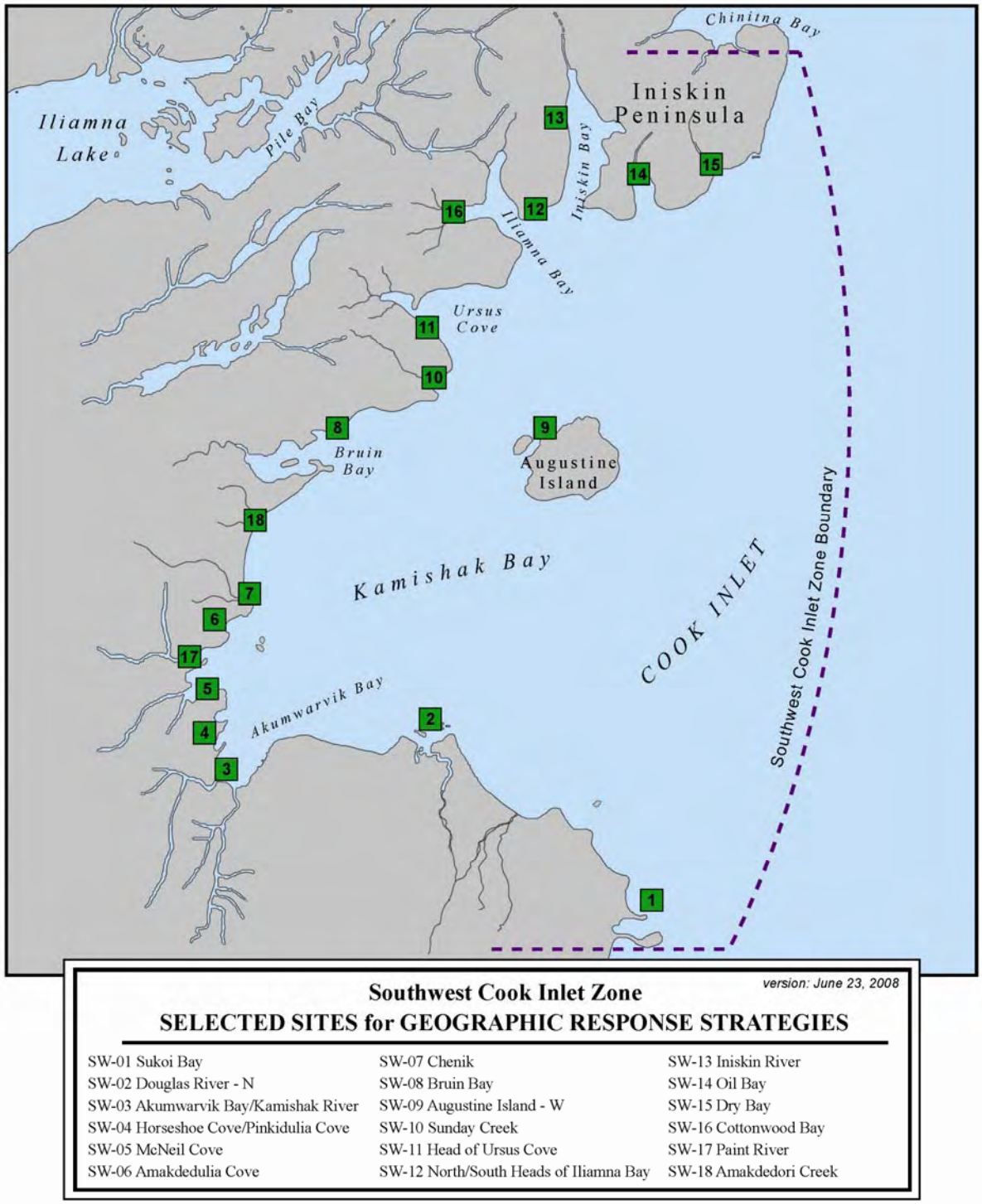
Source: ADEC 2008b.

Figure 6.9. Sites in northern Cook Inlet for which Geographic Response Strategies have been developed.



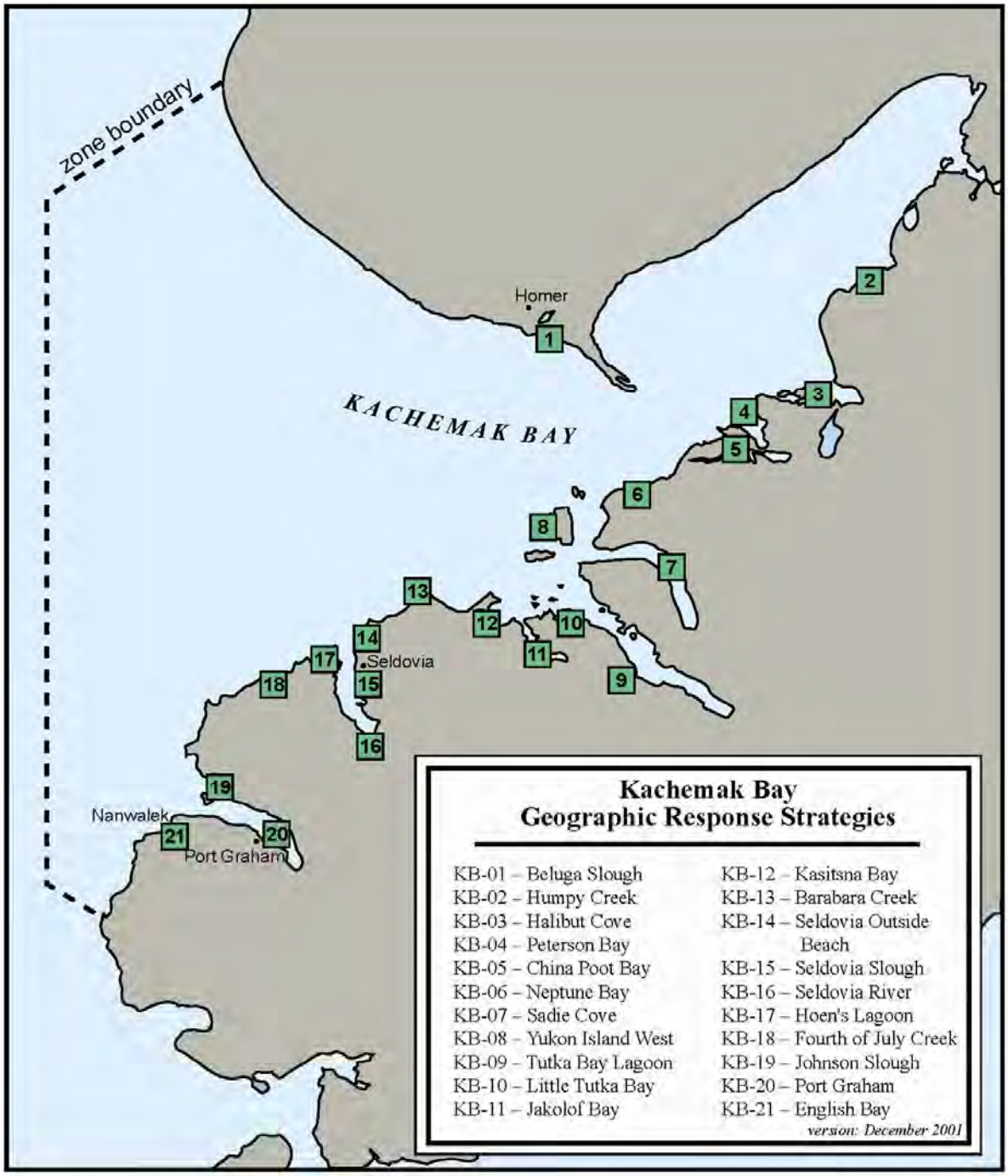
Source: ADEC 2008b.

Figure 6.10. Sites in central Cook Inlet for which Geographic Response Strategies have been developed.



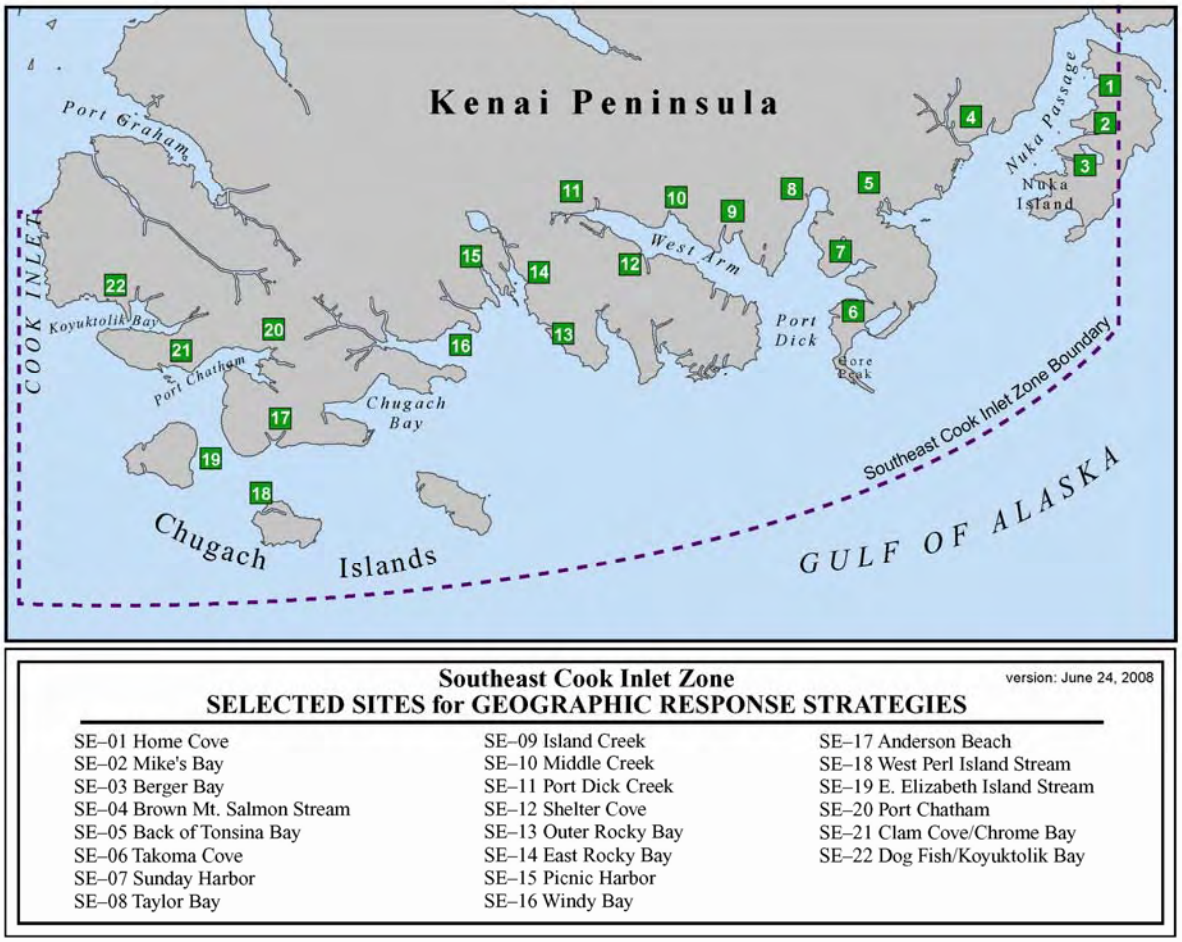
Source: ADEC 2008b.

Figure 6.11. Sites in southwest Cook Inlet for which Geographic Response Strategies have been developed.



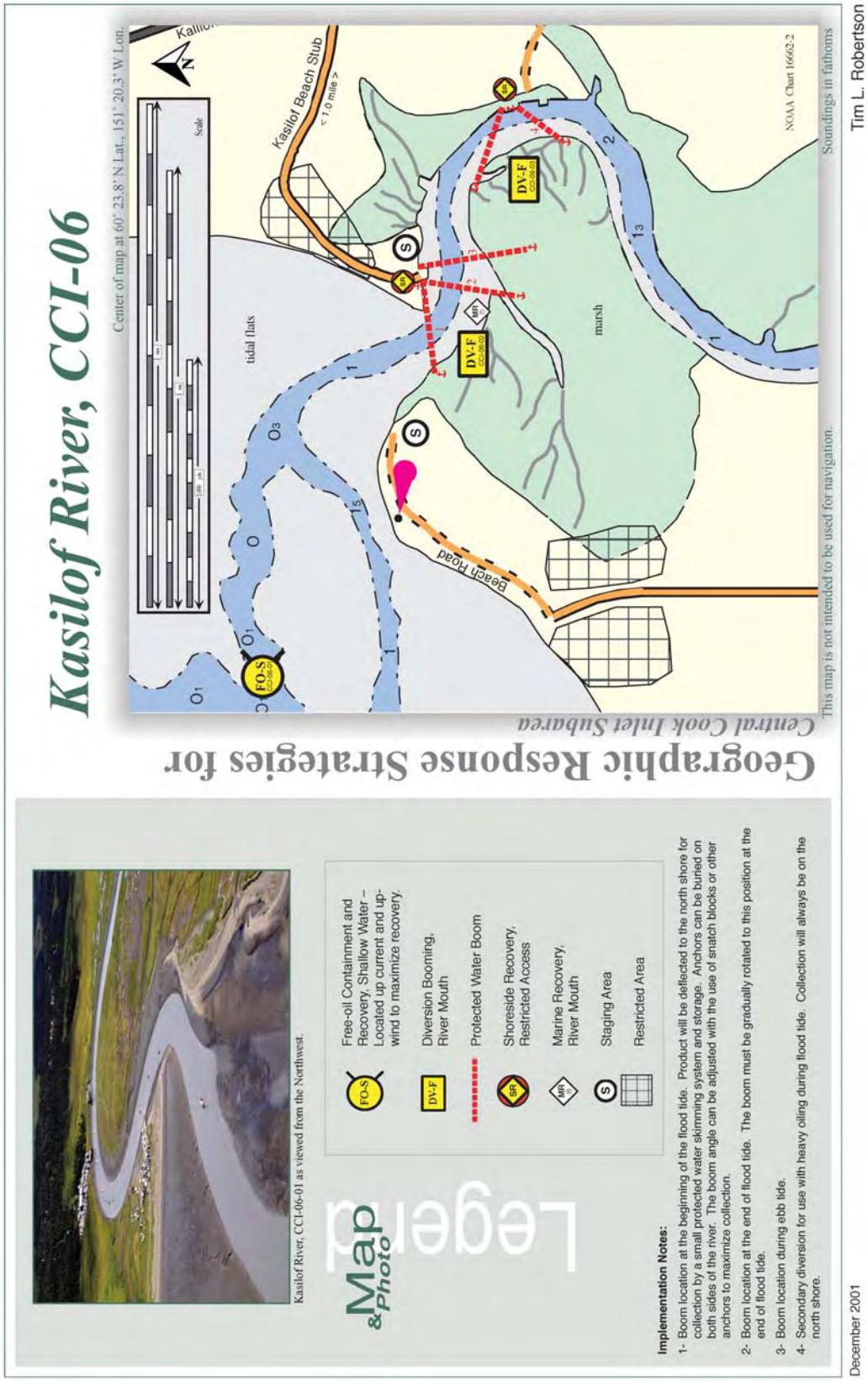
Source: ADEC 2008b.

Figure 6.12. Sites in Kachemak Bay for which Geographic Response Strategies have been developed.



Source: ADEC 2008b.

Figure 6.13. Sites in southeast Cook Inlet for which Geographic Response Strategies have been developed.



Source: ADEC 2008b

Figure 6.14. Example of a Geographic Response Strategy for the Kasilof River.

-continued-

ID	Location and Description	Response Strategy	Implementation	Response Resources	Staging Area	Site Access	Resources Protected (months)	Special Considerations
CCI-06-01	**Kasilof River** Nearshore waters in the general area of: Lat. 60° 23.8 N Lon. 151° 20.3 W	* Maximize on-water recovery in the offshore & nearshore environment / outside the mudflats.	Deploy nearshore strike teams upwind and up current of the river mouth. Use aerial surveillance to locate incoming oil.	Multiple nearshore free-oil recovery strike teams as required to maximize interception of oil before it impacts sensitive areas.	Kasilof Harbor or Kenai Harbor	Via marine waters. See NOAA Charts 16661-1, 16662-1 or 16662-2.	Same as CCI-06-02.	Strong tidal currents, shoal waters and rocks. Vessel master should have local knowledge.
CCI-06-02	**Kasilof River** Lat. 60° 23.13 N Lon. 151° 17.87 W 2.5 nm. north of Cape Kasilof on east side of Cook Inlet River Channel • entrance marked by lighted buoy (May - November). • not navigable at low tide. • strong currents. • narrow and winding. • boats ≤ 6' can navigate in river from entrance to 6 mi. upstream. Docks • located North side of river. • Cook Inlet Processing, 78' dock face, launch ramp and detached float.	* Divert spilled product to designated collection sites *Recover spilled product at designated collection sites. **Seasonal Restriction** River iced-in/not navigable from approximately November to April.	Place 1,000 ft. of diversion boom and collect product with an on-shore and/or marine collection unit.	**Equipment** 5 ea. 200 ft. river boom units 2 ea. protected water skimmer 600 ft. 2" discharge hose 2 ea. on-shore storage unit 12 ea. 40 lb. anchor systems 1 ea. marine storage unit 2000 ft. line **Support** 3 ea. vessel class #5/6 1 ea. truck 1 ea. truck with trailer 1 ea. shelter. 2 ea. ATV trailers 2 ea. ATVs 25 ea. fence posts 1 or 2 light plants **Personnel/Shift** 12 ea. deploy & set-up 8 ea. tend & maintain	**North shore:** • Services - crane, boat launch, electric power, heavy equipment access • Security - none. • Support - shelter. **South shore:** • Private land off Coho Loop • Service - none. • Security - none. • Support - shelter	**FOSC Historic Properties Specialist should INSPECT site prior to operations.** FOSC Historic Properties Title 16 permit may be required to work inside river. Contact Environmental Unit of the Unified Command for permit. **North shore:** Kalifornski Beach Road to Kasilof Beach Road, ends at beach near processor. **South shore:** Coho Loop road to end of dirt road, beach access via ATV or off road equipment. **Seasonal Restriction** Roads not plowed during winter approximately November - April.	• Tidal marshes (all year) • Salmon migration and spawning (May - October) • Intertidal salmon spawning (July - September) • Waterfowl and shore bird concentrations (May - September) • Fishing (July - September) • Heavy recreational use (June - September)	• Very difficult and unsafe to protect exposed tidal flats outside river mouth. • Working on banks of the river should be no problem. Take care not to work or walk on oiled shoreline, to avoid driving oil into the soils. • Access above intertidal area will have to be resolved with landowners before setting anchors or staging areas. **Seasonal** Vessel mooring buoys available during fishing season.
CCI-06-03	**Kasilof River** - Secondary Lat. 60° 22.97 N Lon. 151° 17.27 W Same as CCI-06-02.	* Duplicate primary tactics of diversion & collection further upstream, if required.	Place 1,000 ft. of diversion boom and collect oil with an on-shore unit.	**Equipment** 5 ea. 200 ft. river boom units 1 ea. protected water skimmer 600 ft. 2" discharge hose 2 ea. on-shore storage unit 10 ea. 40 lb. anchor systems 1000 ft. line **Support** 1 ea. vessel class #5/6 1 ea. truck 1 ea. truck with trailer 1 ea. shelter. 2 ea. ATV trailers 2 ea. ATVs 25 ea. fence posts 1 or 2 light plants **Personnel/Shift** 10 ea. deploy & set-up 6 ea. tend & maintain	**North shore:** • Services - crane, boat launch, electric power • Security - none. • Support - shelter. **South shore:** • Private land off Coho Loop • Service - none. • Security - none. • Support - shelter	Permits and inspection required (see CCI 06-02). **North shore:** Kalifornski Beach Road to Trans-Aqua sign, (1/4 mi. past Kasilof beach road). **South shore:** Coho Loop road to end of dirt road, beach access via ATV or off road equipment.	Same as CCI-06-02	Same as CCI-06-02

Figure 6.14 Page 2 of 2.

4. Cleanup and Remediation

Cleanup plans for terrestrial and wetlands spills 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 (Jorgenson and Carter 1996).

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 6.5 lists cleanup objectives and techniques that may be applicable to each objective. Table 6.6 compares the advantages and disadvantages of cleanup techniques for crude oil in terrestrial and wetland ecosystems (Jorgenson and Carter 1996).

Table 6.5. 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 6.6. 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.

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. 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).

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).

5. 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 U.S.C. §9605), and §311(c)(2) of the Clean Water Act, as amended (33 U.S.C. §1321(c)(2)) require environmental protection from oil spills. CERCLA regulations contain the National Oil and Hazardous Substances Pollution Contingency Plan (40 C.F.R. §300). 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)), which 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.

b. Alaska Statutes and Regulations

As discussed above and in Chapter 7, 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 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 prior to 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 cleanup 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 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 drill a relief well, 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, lightening, 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 clean up 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 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 bathymetric and topographic maps, charts, plans, drawings, diagrams, and photographs that describe the facility, show the normal routes of oil cargo vessels, show the locations of storage tanks, piping, containment structures, response equipment, emergency towing equipment, and other related information;
- 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 non-mechanical response information such as in situ burning or dispersant, including an environmental assessment of such use;
- Provide oil spill primary response action contractor information;
- 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 detailed 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

Holders of approved contingency plans must provide proof of financial ability to respond (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 barrels per day of oil;
  - $10,000,000 per incident if the facility produces over 5,000 barrels per day of oil;
  - $5,000,000 per incident if the facility produces over 2,500 barrels per day but not more than 5,000 barrels per day of oil; and,
  - $1,000,000 per incident if the facility produces 2,500 barrels 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
- Non-crude oil vessels and barges: $100 per barrel per incident or $1,000,000, whichever is greater, with a ceiling of $35,000,000

- The coverage amounts are adjusted every third year based on the Consumer Price Index (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. The plan must incorporate the incident command system, identify actions to be taken to reduce the likelihood of occurrence of catastrophic oil discharges and significant discharges of hazardous substances (not oil), and designate the locations of storage depots for spill response material, equipment, and personnel.

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.

6. Mitigation Measures and Other Regulatory Protections

Recognition of the difficulties of containment and clean up 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 best interest finding (see Chapter 9). Additional site-specific and project-specific mitigation measures may be imposed as necessary if exploration and development take place.

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