# CHAPTER 3.0

# OIL AND GAS DEVELOPMENT/PRODUCTION OPTIONS FOR THE ALASKAN BEAUFORT SEA

# TABLE OF CONTENTS

## CHAPTER 3.0 OIL AND GAS DEVELOPMENT/PRODUCTION OPTIONS FOR THE ALASKAN BEAUFORT SEA

## TABLES



## FIGURES

# 3.0 OIL AND GAS DEVELOPMENT/PRODUCTION OPTIONS FOR THE ALASKAN BEAUFORT SEA

## 3.1 INTRODUCTION

Chapter 3.0 presents a broad view of oil and gas technology and options applicable to the development and production of oil and gas in the Alaskan Beaufort Sea. The Northstar project is the first proposal for development and production of oil and gas resources in the Alaskan Outer Continental Shelf (OCS). Oil and gas resources in other areas of the Alaskan Beaufort Sea have been identified, and future development and production activities are likely. Development options and alternatives for this project also may be applicable to development of other OCS resources.

The purpose of this chapter is twofold:

- Provide information for evaluating and selecting specific alternatives for development of the project, as required by the National Environmental Policy Act (NEPA); and

- Present this information in a manner that can be used to evaluate proposals for future OCS oil and gas development in the Alaskan Beaufort Sea.

The following information is presented in this chapter:

- A regional overview of important factors which affect selection of appropriate development technologies and options, including historic oil field development, current operations and facilities, characteristics of potential technologies, and environmental conditions.

- The process used to develop a short list of feasible oil and gas development/production options to be evaluated further in this Environmental Impact Statement (EIS), and applied in Chapter 4.

Chapter 3 addresses the following specific issues/concerns related to the determination of oil and gas development/production options:

| Issues/Concerns | Section |
|---|---|
| · Are existing offshore facilities available for development of new offshore resources? | 3.2.2 |
| · Are existing onshore facilities available for shared use or co-location of facilities required for the handling of new oil production? | 3.3.2 |
| · What environmental characteristics of the Alaskan Beaufort Sea are important to design and operation of offshore oil and gas facilities? | 3.4.1 |
| · What activities are involved in the exploration and development of offshore oil and gas resources? | 3.4.2.1 |
| · How does drilling technology affect options for developing oil and gas resources? | 3.4.2.3 |
| · What are the characteristics of different offshore oil and gas production structures? | 3.4.2.4 |
| · Are different options available for processing produced oil and gas? | 3.4.2.6 |
| · What alternatives are available to transport oil? | 3.4.2.7 |
| · What happens to industrial facilities at the end of the project life? | 3.4.2.8 |
| · How can information about the environment and oil and gas facilities be used (or applied) to identify reasonable project alternatives? | 3.5 |

## 3.2 OFFSHORE OIL AND GAS ACTIVITIES AND FACILITIES

### 3.2.1 Oil and Gas Leasing Programs in the Alaskan Beaufort Sea

The Alaska Department of Natural Resources, Division of Oil and Gas regulates oil and gas activities in Alaska, including submerged lands within 3 nautical miles (5.6 kilometers [km]) of the coast. The U.S. Minerals Management Service (MMS) regulates oil and gas exploration and development activities in waters beyond the 3 nautical mile (5.6 km) limit of state ownership within U.S. territorial waters. This federal offshore area is referred to as the OCS. The Bureau of Land Management (BLM) is responsible for oil and gas leasing on federal onshore land such as the National Petroleum Reserve, Alaska (NPRA). The U.S. Fish and Wildlife Service has responsibility for oil and gas leasing within federally designated wildlife refuges such as the Arctic National Wildlife Refuge (ANWR). However, by law, petroleum exploration, leasing, and development are prohibited in ANWR (Section 1003, Alaska National Interests Lands Conservation Act).

Lease sale planning involves a number of state and federal government agencies, industry, and the public. Prior to scheduling a state or federal lease sale, oil companies are asked to nominate geographic areas of interest. A proposed lease sale schedule is developed and released for comment. Additions and revisions are made to the proposed lease schedule based on comments received. The MMS prepares EISs for lease sales as required by the NEPA. The state conducts an environmental review under its own regulations and holds public hearings.

Oil and gas lease sale plans are developed every 5 years by the MMS and the Alaska Division of Oil and Gas, and lease sales are conducted in accordance with these plans. The most recent federal sale in the Alaskan Beaufort Sea was Lease Sale No. 170, held August 5, 1998, and the most recent state sale on the

North Slope was Lease Sale No. 87, held June 24, 1998. A summary of past and proposed Alaskan Beaufort Sea federal and state lease sales is presented in Table 3-1. Federal sales resulted in issuance of 660 federal leases to date. Of the 660 leases issued, 584 have expired or have been relinquished. More than 46 million acres (18 million hectares) have been offered for lease, and approximately 3.1 million acres (1.24 million hectares) have been leased.

Discoveries resulting from the first offshore lease sale, held jointly between the State of Alaska and the Federal Government (December 11-12, 1979), include the Point McIntyre, Niakuk, Endicott, and Northstar reservoirs. The first three were brought into production by directional drilling from land or an island accessed by a causeway to shore. Northstar is the first reservoir to be proposed as an offshore development. Other offshore discoveries from more recent lease sales include Badami, Sandpiper, Tarn (now Liberty), Hammerhead, Kuvlum, and Flaxman reservoirs. Development plans for the Liberty reservoir proposed by BP Exploration (Alaska), Inc. (BPXA) include construction of a new gravel island with a buried subsea pipeline being considered to bring production to shore. The MMS is in the process of preparing an EIS on the proposed Liberty development project.

### 3.2.2 Existing Offshore Oil and Gas Facilities

An understanding of the existing facilities in the Prudhoe Bay area is important to develop alternatives for offshore development proposals. With regard to the development of new offshore reservoirs, the location of existing offshore facilities such as gravel islands that have been previously used for exploration activities is particularly useful. These facilities may provide opportunities for the development of offshore oil and gas resources if located within reasonable proximity to the reservoir to be produced (Section 3.4.2.3 explains the potential reach of drilling technology). Use of existing sites could allow the development of new petroleum resources while limiting the need to construct new offshore structures.

Seventeen gravel islands have been constructed in the Alaskan Beaufort Sea for exploration drilling since 1975. Most islands remain in some form; however, erosion protection has been removed from a number of them. One, NW Milne Island, was partially removed as its gravel was reused to construct a portion of the new F Pad in the Milne Point Unit. Water depth, year of construction, construction type, and the location of manmade islands in the Alaskan Beaufort Sea are shown on Figure 3-1. These include Seal and Northstar Islands within the Northstar Unit (a unit is a legal designation given to a group of leases which may be owned by multiple parties that are combined to allow the efficient and coordinated development of resources extending across lease boundaries within the unit). Seal and Northstar Islands were abandoned by removal of all equipment and erosion protection.

Table 3-1 (1 page)

Figure 3-1 (page 1 of 2)

Figure 3-1 (page 2 of 2)

The natural barrier islands also have been used for exploration drilling activities, as temporary camp locations, for gravel storage (Ashford, 1983:205), and as staging areas for other materials such as drill pipe and oil spill response equipment in support of exploration activities. In addition to gravel islands, ice islands have been constructed for exploration drilling during winter. Drillships and bottom-founded drilling structures also have been used for exploration drilling in the Alaskan Beaufort Sea. One of these, the bottom-founded Concrete Island Drilling Structure (CIDS), is currently located in Camden Bay off the coast of ANWR. The CIDS and other exploration structures may be suitable (Section 3.4.2.4), with modification, for use as offshore production structures.

Existing onshore and offshore facilities in the Prudhoe Bay area are likely to provide support for future oil and gas development/production in the Alaskan Beaufort Sea. It usually would be more economical to use existing facilities than to build new ones, especially if they have excess capacity. Because offshore development is likely to connect to or use existing facilities, such as the Trans Alaska Pipeline System (TAPS), the Dalton Highway, and processing facilities, a brief explanation of existing onshore facilities is provided below.

## 3.3 ONSHORE OIL AND GAS ACTIVITIES AND FACILITIES

### 3.3.1 Historical Setting

Interest in northern Alaska oil and gas resources began with discovery of oil seeps on the Arctic Coastal Plain in 1904. Land was set aside as a petroleum reserve and exploration drilling was conducted within this area (NPRA) in the 1940s and 1950s (Schindler, 1982:i). Oil and gas discoveries were documented, but not considered commercially viable. Leasing by BLM and the state in the 1950s and 1960s promoted further exploration between the NPRA (to the west) and what is now designated ANWR (on the east) (Figure 2-1). ARCO Alaska, Inc. (ARCO) and Humble Oil discovered the giant Prudhoe Bay reserve in 1968. ARCO initially estimated the Prudhoe Bay discovery at nearly 10 billion barrels of recoverable reserves. The size of the discovery triggered further exploration in the area by British Petroleum, ARCO, and others.

The Prudhoe Bay discovery raised the question of how to get oil from the North Slope to world markets. Options proposed at the time included tankers, railroads, submarines, and pipelines. Railroads and submarines were not seriously considered due to economics. Tanker travel to and from the Alaskan Beaufort Sea was tried in 1969. A single trip through the Northwest Passage suggested that while the trip was possible, tankering could not compete economically or practically with a pipeline. In addition, transport by tankers in the Alaskan Beaufort Sea would be limited by weather and ice, and would increase the risk of oil spills. Ultimately, TAPS was constructed from the North Slope to an oil terminal in Valdez.

Recent discoveries near the NPRA have resulted in a renewed interest in potential leasing of this area. Exploration immediately east of the NPRA border near the Colville River resulted in the discovery of the Alpine Reservoir, estimated to contain 300 to 400 million barrels of oil in place. The northeast portion of NPRA is currently under consideration for oil and gas leasing by the BLM.

### 3.3.2 Existing Onshore Oil and Gas Facilities

Existing onshore facilities may provide opportunities for shared use or co-location of pipelines and processing facilities required for the handling of oil production from new developments. This sharing or co-location of facilities could reduce the extent of new onshore development or the geographic distribution of industrial facilities in the Prudhoe Bay area. The community of Deadhorse is an example.

Deadhorse is an unincorporated industrial community established in the late 1960s to support the developing North Slope oil industry and related service businesses. Deadhorse has a state operated airport with regular commercial service. It is located on the banks of the Sagavanirktok River, 7.5 miles (12 km) south of Prudhoe Bay. Business occupancy has changed over the years as oil field needs changed; however, services for travelers are growing due to tourism. The population of Deadhorse is highly variable, as most of these people work on the North Slope in shifts and commute from primary residences elsewhere.

Development cost and regulatory requirements result in some oil field facilities being shared between the two main operators on the North Slope, BPXA and ARCO. For example, processing facilities originally constructed to support development of one oil field may be used for nearby developments as additional discoveries are made. Milne Point processing facilities and pipelines are being used to process oil from the Cascade and West Sak oil fields. The seawater treatment plant (STP) on the northern end of the West Dock causeway supports secondary oil and gas recovery in the east (ARCO operated) and west (BPXA operated) portions of the Prudhoe Bay reservoir and the Milne Point (BPXA operated) reservoir. The STP currently processes 390,000 barrels per day (barrels/day) of water, and has the capacity to process 1.2 million barrels/day treated seawater (Rainwater - Pers. Comm., 1997:1). The West Dock causeway has several owners and is shared for loading/unloading vessels, supporting offshore exploration, and as a production drillsite for the Point McIntyre reservoir.

Pipelines that carry oil between units require a state right-of-way permit and are designated as common carrier pipelines. Common carrier pipelines can be accessed by companies other than the operator to transport oil to Pump Station No. 1 at the beginning of the TAPS. The TAPS is also a common carrier pipeline. Processing and pipeline transport fees are negotiated between the controlling operator and the purchaser.

The TAPS Pump Station No. 1 lies just to the south of the oil field units and is the collecting point for all oil products entering the approximately 800-mile (1,288 km) long TAPS. The facility, covering approximately 112 acres (45 hectares) currently handles about 1.45 million barrels/day of oil, but has a capacity for up to 2.2 million barrels/day. To date, more than 12.5 billion barrels of oil have been transported from the North Slope to the marine terminal at Valdez through the TAPS.

In addition to the shared use of processing facilities and pipelines, oil spill response capabilities have been developed under cooperative agreements among several operating companies. BPXA, ARCO, and the Alyeska Pipeline Service Company have established a mutual aid agreement to assist each other with response equipment and personnel in the event of an oil spill or mutual aid drill. These companies and

Exxon Company USA are members of Alaska Clean Seas (ACS), a non-profit oil spill response cooperative. ACS is a full response organization and currently functions as the focal point for spill response and training for member companies. ACS provides equipment, training, and personnel for oil spill response preparedness, response, and cleanup. The ACS administration offices, response command center, central communications system, and main warehouse are located in Deadhorse. During the open water season, ACS stages response equipment (including vessels) at West Dock and East Dock in Prudhoe Bay and additional equipment at the confluence of the east and west channels of the Sagavanirktok River. Additional resources currently available in the event of a spill include: trained village response teams, Cook Inlet Spill Response and Prevention Incorporated, Alyeska Pipeline Service Company Ship Escort/Response Vessel System in Prince William Sound, the U.S. Coast Guard Strike Team, and the U.S. Navy Supervisor of Salvage response equipment inventory.

Current and proposed oil and gas facilities on the North Slope include those at the Alpine, Kuparuk, Tarn, West Sak, Milne Point, Prudhoe Bay, Point McIntyre, Lisburne, Niakuk, Endicott, Badami, and Cascade reservoirs (Figure 3-2 a through c). The facilities associated with these developments are described below and summarized in Table 3-2. The design and operating capacities for these onshore facilities are summarized in Table 3-3.

**Alpine:** Plans to develop ARCO's Alpine Unit, located 34 miles (55 km) west of Kuparuk in the western Colville River Delta, were announced October 2, 1996 (ARCO, 1996:1-4). Original oil in place is estimated at 800 million to 1 billion barrels, with 250 to 300 million barrels potentially recoverable using current technology (Nelson, 1996:30). Six wells, four side-track wells (a well drilled from an existing wellbore that is directionally drilled to another point), and a three-dimensional seismic survey indicate that the reservoir is approximately 10 miles (16 km) long, covering approximately 40,000 acres (16,188 hectares). Development is proposed from two gravel pads connected by 3 miles (4.8 km) of gravel road. One gravel pad, Alpine Pad 1, is approximately 85 acres (34.4 hectares) in size and will be used for the central oil processing facility, employee accommodations, maintenance facilities, and some drilling equipment. The second gravel pad, Alpine Pad 2, will be used for wellheads. A 34-mile (55 km) long pipeline will connect Alpine production to the Kuparuk pipeline, and TAPS. Daily production is expected to peak between 50,000 and 80,000 barrels/day oil, and production could start as early as the year 2000 (ARCO et al., October 1996:2-1). The right-of-way was granted by the Alaska Department of Natural Resources on December 15, 1998. In addition, a seawater pipeline will transport water for waterflood from Oliktok Point to water injection wells.

**Kuparuk Reservoir Facilities and Pipelines:** The Kuparuk reservoir was discovered in 1969 and began production in 1981. There are an estimated 5.9 billion barrels of original oil in place and 2.8 trillion standard cubic feet of original gas in place (BPXA, 1997:18). The Kuparuk facilities are operated by ARCO. Kuparuk road and well pads extend to or near the coastline at several points. There currently are 462 oil production

Table 3-2 (1 page)

Figure 3-2a (page 1 of 2)

Figure 3-2a (page 2 of 2)

Figure 3-2b (page 1 of 2)

Figure 3-2b (page 2 of 2)

Figure 3-2c (page 1 of 2)

Figure 3-2c (page 2 of 2)

Table 3-3 (1 page)

wells, 300 gas injection wells, and 162 water injection wells. The Kuparuk oil pipeline to TAPS is a common carrier pipeline.

**Tarn Reservoir Facilities and Pipelines:** The Tarn discovery was announced in March 1997, and plans to develop were announced by ARCO and BPXA in April 1997. The field is located 10 miles (16 km) west of Kuparuk and covers approximately 161,000 acres (65,157 hectares). Tarn is estimated to contain approximately 65 million barrels of recoverable reserves. The discovery well test flowed 2,000 barrels of 38° API gravity oil from a reservoir depth of approximately 5,200 feet (ft) (1,585 meters [m]). Gravel placement started in December of 1997. First Production from Pad 2N occurred in July 1998 and Pad 2L began producing in December of 1998. The initial phase of construction is complete, but additional facilities are required to fully develop the reservoir. The initial facilities include a road, flow line, injection line, and power line back to the existing Kuparuk infrastructure, approximately ten miles. The reservoir is being developed from two well pads with slots for up to 40 production and injection development wells. There are currently 16 oil production wells and 6 gas injection wells. Some additional work is planned for 1999 but the pace of the next phase has been slowed due to low oil prices.

**West Sak Reservoir Facilities and Pipelines:** West Sak, owned by ARCO, is shallow, low-temperature, heavy oil accumulation that overlies the Kuparuk formation. Discovered in 1969, it is estimated by ARCO to hold 3 million barrels of original oil in place, with 300 to 500 million barrels of recoverable oil. Delineation of the reservoir began in 1971 and continued through 1982. An experimental development program undertaken by ARCO from 1983 to 1986 yielded approximately 760,000 barrels of oil before it was abandoned. Production is expected to resume in late 1998, with oil sent to the Kuparuk processing facilities. Phase One of the development (fall of 1998) will have 25 production wells and 25 water injection wells. Production will be about 7,500 barrels/day. Development drilling will continue intermittently for approximately 12 years and may result in 500 wells. Production is expected to be approximately 60,000 barrels/day (Jones, 1996: C-8). Development may require several drilling pads because of the shallow reservoir (about 3,500 ft [1,067 m]). The majority of the oil is heavy and thick, requiring a relatively long time period to deplete the reservoir. Waterflood or miscible gas injection may be required to assist oil flow to the wells (Thomas et al., 1993: xiii). Half the wells will be drilled for oil production and the other half for water or miscible gas injection.

**Milne Point Reservoir Facilities and Pipelines:** Milne Point reservoir was discovered in 1969 and began production in 1985. The reservoir contained an estimated 3.3 billion barrels of original oil in place. Production is expected to increase from current levels (Table 3-3) with additional oil from the Cascade reservoir, additional oil production wells installed within the Milne Point reservoir, and the planned expansion of more than 500 new wells over the next 12 years for the West Sak reservoir (BPXA, 1997:22; White, 1998:F1). The Milne facilities are operated by BPXA.

Milne Point facilities are located northeast of the Kuparuk reservoir and several roads and pads extend to or near the coastline. Currently, there are 140 oil production wells and 63 water injection wells. Milne Point recently expanded F-Pad into Simpson Lagoon to allow additional wells to be drilled. The Milne Point common carrier pipeline joins the Kuparuk common carrier pipeline about 11 miles (17.7 km) south of the Milne Point facilities and continues on to the TAPS.

**Prudhoe Bay Reservoir Facilities and Pipelines:** The Prudhoe Bay reservoir was discovered in 1968 and began production in June 1977. Original in place reserves are currently estimated to be 25 billion barrels of oil, and 47 trillion cubic feet of gas (BPXA, 1997:20). Recoverable reserves are estimated at 12 to 13 billion barrels of oil. Production is declining at a rate of about 10 percent (%) per year (BPXA, 1997:17). The Western Operating Area of the Prudhoe Bay Unit is operated by BPXA, and the Eastern Operating Area is operated by ARCO. These facilities are shown on Figure 3-2b.

Prudhoe Bay facilities include six oil processing facilities that are operating at full capacity for gas and water. Facilities would need to be expanded to handle additional gas or water from other reservoirs. Currently, there are 1,079 oil production wells, 36 gas injection wells, and 182 water injection wells, with projected increases to 1,180 oil production wells and 300 water injection wells (BPXA, 1997:17).

The West Dock causeway is a manmade, solid-fill gravel structure with a 650-ft (198 m) bridge span between Dock Head 2 and Dock Head 3, and a 50-ft (15.2 m) bridge span seaward of Dock Head 3. West Dock extends into water depths of approximately 12 ft (3.6 m). The 50-ft (15.2 m) opening is filled with gravel and no longer allows flow of water. An STP located at the end of West Dock provides a water source to support a waterflood program for the Point McIntyre reservoir. The causeway is owned by BPXA, ARCO, and other companies of the Prudhoe Bay Unit. It is used for mooring and unloading small vessels and barges, providing access to the STP, and housing the Point McIntyre 2 (PM2) drill pad. Multiple pipelines and cables to and from the STP and drill pad PM2 run along and within the causeway.

East Dock, the first dock built during development of the Prudhoe Bay oil fields, is a solid-fill gravel structure, extending approximately 80 ft (24.4 m) into the water along the eastern shore of Prudhoe Bay. Only small, shallow draft vessels can use East Dock because of the shallow 6 ft (1.8 m) water depth. Most docking and mooring activities were moved to West Dock after it was constructed into deeper water.

**Point McIntyre Reservoir Facilities and Pipelines:** The Point McIntyre reservoir was discovered in 1989 and began production in 1993. The reservoir contains an estimated 800 million barrels of original oil in place and 0.9 trillion standard cubic feet of original gas in place. Recoverable reserves are estimated at 400 million barrels of oil. Point McIntyre facilities are operated by ARCO.

The Point McIntyre 1 drill pad is located approximately 250 ft (76 m) inland from the coast; drill pad PM2 is located approximately 2 miles (3.2 km) offshore along the West Dock causeway. Currently, there are 48 oil production wells, 1 gas injection well, and 14 water injection wells. All wells have been directionally drilled from these two sites to reach reserves in the nearshore region. Projections are for an additional 23 oil production wells, 1 gas injection well, and 3 water injection wells in the near future. Three-phase fluids (combination of oil, gas, and water) from Point McIntyre are routed to Lisburne facilities for separation and transport to the TAPS.

**Lisburne Reservoir Facilities and Pipelines:** The Lisburne reservoir was discovered in 1968 and began production in 1986. There are an estimated 2 billion barrels of original oil in place, and recoverable reserves are estimated at 300 million barrels of oil. The Lisburne facilities are operated by ARCO.

The Lisburne processing facilities are located near the southeast shoreline of Prudhoe Bay. The Lisburne Processing Center is a shared production facility, processing fluids from Lisburne, Point McIntyre, North Prudhoe Bay State, and Niakuk reservoirs (BPXA, 1997:21). Lisburne currently has 78 oil production wells, and 4 gas injection wells. Two additional oil production wells are planned. The Lisburne crude oil pipeline to the TAPS is a common carrier pipeline.

**Niakuk Facilities and Pipelines:** The Niakuk reservoir was discovered in 1985 and began production in 1994. The reservoir contains an estimated 200 million barrels of original oil in place and 130 billion standard cubic feet of original gas in place. Recoverable reserves of oil and gas liquids are estimated at 75 million barrels. The field is operated by BPXA.

The Niakuk reservoir is accessed from a drill pad at Heald Point. Currently, there are 12 oil production wells and 4 water injection wells, which are projected to increase to 14 and 7, respectively (BPXA, 1997:23). Produced fluids are processed at the Lisburne Production Center and transported to the TAPS via the Lisburne common carrier pipeline.

**Endicott Reservoir Facilities and Pipelines:** The Endicott reservoir was discovered in 1978 and began production in 1987. There is an estimated 1.1 billion barrels of original oil in place and 1.4 trillion standard cubic feet of original gas in place. Recoverable reserves are estimated at 660 million barrels of oil. Endicott is operated by BPXA.

The Endicott development is located on two manmade gravel islands linked to the mainland by a breached gravel causeway approximately 5 miles (8 km) long. One island houses wells and gathering pipelines, and the second island includes living quarters and processing facilities. Currently, there are 74 oil production wells, 5 gas injection wells, and 28 water injection wells. Oil production wells are expected to increase by 20, and water injection wells will increase by 2 in the near future. The Endicott oil pipeline is a common carrier pipeline to the TAPS and could be used to transport processed crude from future development to the east. Up to 35,000 barrels/day oil from Badami was routed through the Endicott pipeline beginning in 1998.

**Badami Reservoir Facilities and Pipelines:** The Badami reservoir was discovered in 1990 and began production in late 1998. The Badami reservoir is located 25 miles (40.2 km) east of the Prudhoe Bay reservoir. Recoverable reserves are estimated at 150 million barrels of oil (BPXA, 1995a:1-1). The Badami Unit is operated by BPXA.

Two drilling pads and up to 50 wells are expected to fully develop this field. The wells will be directionally drilled to the reservoir from the gravel pad. An approximate 35-mile (56 km) long common carrier pipeline corridor from Badami ties into the Endicott common carrier pipeline for transport to the TAPS.

**Cascade:** Cascade is an onshore discovery located east of and is considered part of the Milne Point Unit with estimated potential reserves of 12 million barrels of oil. Initial production began in 1997. Cascade routes oil to the Milne Point processing facility and produces an estimated 8,000 barrels of oil per day. Development includes the construction of a 7-mile (11.2 km) pipeline to existing processing facilities, gravel well pad, gathering pipelines, and 8 oil production wells.

## 3.4 ANALYSIS OF OIL AND GAS DEVELOPMENT OPTIONS FOR THE ALASKAN BEAUFORT SEA

### 3.4.1 General Characteristics of Alaska's Beaufort Sea and Arctic Coastal Plain Environments

The following discussion about the physical, biological, and human environment of Alaska's Arctic Coastal Plain and Beaufort Sea is intended to provide information pertinent to considering options for working in this area. The technical and logistical methods required to develop oil and gas resources in the Arctic are determined in part by environmental conditions. The following discussions present a cursory overview of environmental conditions without specific reference to cited literature; additional information can be found in Chapters 5, 6, and 7 and in literature cited within those chapters.

#### *3.4.1.1 Physical Environment*

**Offshore:** The Beaufort Sea comprises the southern part of the Arctic Ocean, extending between Canada's Banks Island to the east and the Chukchi Sea to the west. The 37- to 75-mile (60 to 121 km) wide continental shelf beneath the Alaskan Beaufort Sea portion extends from the Canadian border west to the Barrow Sea Valley. The seafloor is mostly flat and featureless, and gradually dips in a northerly direction. Water depths on the continental shelf generally are less than 600 ft (183 m). Characteristically, bottom sediments are composed of sands and silt. An exception is the area near the Sagavanirktok River Delta where a collection of boulders and cobble (the Boulder Patch) have been identified. This unusual hard substrate provides habitat diversity which supports a biological community uncommon in the Alaskan Beaufort Sea. As a consequence, this substrate is of particular interest to resource agencies. Recent surveys suggest that rocky substrates are more widespread than previously believed; however, the majority of the seabottom is fine-grained material. A series of natural barrier islands parallel portions of the coastline 1 to 20 miles (1.6 to 32 km) offshore. The low relief barrier islands are continuously reshaped as a result of currents and erosion.

Nearshore currents primarily are wind-driven between the Alaskan Beaufort Sea coastline and the barrier islands during the open water season (Section 5.5.1). Currents usually flow parallel to the coast (east-west) at speeds between 0.1 to 0.3 miles per hour (mph) (0.2 to 0.5 km/hour) during summer. Currents beneath the ice are much slower than wind-driven currents and generally are less than 0.1 mph (0.2 km/hour).

Zones of sea ice found in the Alaskan Beaufort Sea include: the landfast zone, stamukhi (shear) zone, and the pack-ice zone (Section 5.6). The landfast ice zone usually extends from shore to water depths of approximately 65 ft (20 m) in winter, with ice thickness of 4 to 7 ft (1.2 to 2.1 m). Ice freezes to the seafloor in depths less than 7 ft (2.1 m) and becomes bottomfast, or grounded. The remainder of the landfast ice is floating within deeper water. Seaward of the landfast zone is the stamukhi zone. In the stamukhi zone relatively stable landfast ice and mobile pack-ice interact, resulting in ice ridges and open water leads. The stamukhi zone typically extends from water depths of 65 ft (20 m) to the edge of the continental shelf. The pack-ice or polar pack-ice zone, which is the body of ice that never completely thaws, extends seaward of the stamukhi zone and covers much of the northern Arctic Ocean. This zone includes first-year ice, multi-year ice, and large ice islands.

Sea ice conditions vary seasonally and affect the scheduling and nature of construction and operation activities for offshore facilities in the Alaskan Beaufort Sea. The solid ice season usually occurs from November through April. During this period, offshore construction in the landfast ice zone can occur from the ice surface. Ice roads are generally used for access during this period. Offshore ice roads are typically constructed using seawater with a freshwater ice cap. The springtime broken ice season extends from mid-May to mid-July. Another broken ice season occurs during fall freezeup from mid-September to November. During broken ice seasons, access to offshore structures is by helicopter. Boats can be used during the open water and light ice season from mid-July to mid-September.

Sea ice also affects the seafloor topography. Landfast sea ice adjacent to river deltas becomes flooded during early stages of breakup (mid-May to early June) with meltwater from inland drainages that thaw before coastal areas. Drainage of this floodwater through holes in floating sea ice typically occurs in water depths between 6 and 20 ft (1.8 and 6 m). This drainage results in an erosive phenomenon on the seafloor called strudel scouring, which excavates depressions in the seafloor. Strudel scour depressions as large as 5.7 ft (1.7 m) in depth and 90 ft (27 m) in diameter have been documented (Section 5.6). Erosion caused by strudel scour must be considered in the design of offshore structures or pipelines in the landfast ice zone.

Portions of the Alaskan Beaufort seafloor are marked by long linear depressions from ice gouging. Ice gouging is caused by grounding and movement of large pieces of ice in response to winds and currents. Ice gouging along the seafloor is most common in water depths of approximately 50 to 66 ft (15.2 to 20 m). At a 32.5 ft (9.9 m) water depth, ice gouges of up to 2 ft (0.6 m) deep have been recorded. Recorded seafloor depressions from ice gouging in the Alaskan Beaufort Sea ranged up to 8.5 ft (2.6 m) in depth, and occurred in 125 ft (38 m) of water (Section 5.6). Risk of damage to structures or pipelines from ice gouging varies with water depth and pack ice dynamics.

**Onshore:** The Arctic Coastal Plain extends north from the Brooks Range foothills to the Arctic Ocean. It is characterized by flat to gently rolling terrain. Much of the Arctic Coastal Plain is covered by shallow thaw-lake basins, ponds, and deeper lakes. Topographical features are related to permafrost (e.g., pingos, polygons) and river drainages. Several large rivers transect the coastal plain, forming deltas along the shoreline of the Alaskan Beaufort Sea. The coastline consists of beach bluffs, bays, spits, and bars characteristic of dynamic shorelines.

The Arctic Coastal Plain has a mean annual temperature of 11 degrees Fahrenheit (-12.2 degrees Celsius). Average annual precipitation ranges from 4.8 inches (12.2 centimeters [cm]) at Barrow to 6.5 inches (17.0 cm) at Barter Island and occurs mostly as rain in summer. Annual average precipitation recorded at

Prudhoe Bay from 1983 and 1993 indicate 7.0 inches (17.8 cm) of rain/snow fall. The annual average wind speed at Deadhorse Airport is 13.3 mph (21.4 km/hour). Dominant wind direction is from the east during May through December and from the west during January through April. Although some oil and gas activities are possible during summer, the majority of construction in the Arctic is done during winter because frozen ground and frozen sea ice provide solid surfaces for access to work sites without construction of permanent roads. Work is discontinued in extreme wind and cold, but vertical support member (VSM) installation, pipeline construction, excavation of gravel from mine sites, placement of gravel for roads and pads, and movement of large modules or drill rigs over roads or over ice are routinely conducted in sub-zero temperatures. Fog develops along the coast during the open water season (mid-June through mid-September) and frequently limits air travel. Boat travel also can be limited by ice incursion into the nearshore area during summer.

Permafrost is frozen ground that remains at below freezing temperatures continuously from one winter to the next (Section 5.3). It is believed to be continuous throughout the Arctic Coastal Plain to depths of approximately 2,200 ft (671 m). The existence and thickness of subsea permafrost depends on seawater temperature and salinity, extent of shorefast ice in winter, proximity to large rivers, and large-scale sea level fluctuations that occurred during late Pleistocene and Holocene times (less than 17,000 years before present). Construction activities on permafrost can cause thawing and settlement of the previously frozen soils, resulting in damage to structures. Common practices in the Arctic include insulating soils to prevent thawing, and winter construction to minimize impacts to the surface. Winter construction also avoids working on the seasonally thawed soils at the surface which are saturated with water. Temporary ice roads are often constructed during winter across the tundra and ponds to access work sites. Rolligons and tracked vehicles are used with little damage to the vegetation or soil once the soil is frozen to a depth of 12 inches (31 cm); this depth of frost usually occurs by December and lasts through May.

#### *3.4.1.2 Biological Environment*

**Coastal and Offshore Ecosystem:** The Beaufort Sea is dominated by ice. In coastal areas, ice covers the water for 9 months or more each year, except for occasional open water leads. Sea ice along the shoreline frozen to the seafloor essentially becomes an extension of the land and provides a solid substrate for year-round inhabitants, including polar bears and seals. Coastal areas, including lagoons inside the barrier islands, have open water earlier in summer than areas further offshore (Section 5.6.1). Islands provide important habitat and protection from terrestrial predators for nesting common eiders, glaucous gulls, and Arctic terns (Section 6.7). The lagoon systems provide a protected, low salinity corridor for movements and feeding of fish and for feeding, resting, and molting water birds.

Jaegers, gulls, and terns usually are present in coastal areas during summer, while tundra-nesting waterfowl (e.g., eiders, oldsquaw, geese) and shorebirds (e.g., phalaropes) may appear on lagoon and protected nearshore waters in large molting and post-breeding flocks later in summer. Feeding in marine areas may be critical for these birds throughout the summer. The marine invertebrates and fish the birds feed on prepare them for breeding and migration. For some loons, marine waters are the source of fish which adults feed to young, although the young remain on freshwater ponds until they can fly.

Marine fish generally remain in higher salinity marine waters deeper than 12 to 15 ft (3.7 to 4.6 m), except for Arctic cod, which also may be found in nearshore waters during summer. Arctic cod are an important food resource for larger fish and seals (Section 6.4). Char, Arctic cisco, least cisco, and broad whitefish move from rivers into nearshore waters, particularly the lagoons inside of the barrier islands during summer, when freshwater discharge from rivers creates a zone of relatively warm, low salinity water along the coast (Section 6.4). These species are an important subsistence resource across the North Slope and for a commercial fishery on the Colville River Delta (Sections 6.4 and 7.3).

Large animals of the offshore ecosystem include polar bears; ringed, bearded, and spotted seals; and bowhead and beluga whales. Polar bears and ringed and bearded seals are year-round inhabitants and are closely tied to the sea ice (Section 6.5). Because seals are the primary food of polar bears, the bears usually follow the seals. Bowhead whales are migratory, moving eastward in spring through the offshore leads of the Alaskan Beaufort Sea and westward in fall closer to shore (Section 6.9). Like bowheads, beluga whales are migratory and are not dependent on sea ice, but are often associated with sea ice in the Alaskan Beaufort Sea. Open water leads and ice thickness are important factors for these marine mammals. Local residents rely on these species to a varying extent for subsistence, with bowhead whales and seals being the most important in terms of volume of food harvested (Section 7.3). The Beaufort Sea polar bear population currently contains about 1,800 animals (Amstrup, 1995: 187-188). The mean Alaskan subsistence harvest for the Beaufort Sea is 36 bears per year, and the overall (Canada and United States) subsistence harvest is 62 bears per year, but could approach the maximum sustainable harvest rate (80 bears). Polar bears are closely tied to the movement of sea ice in the Beaufort Sea (Canada and Alaska). They usually reach the coastal areas near Kaktovik and Barrow in September and October and may be present in these areas until they leave with the receding ice during April and May. Polar bears move along the coast to search for mates or carcasses, move between feeding locations, and search for denning areas in the fall. Polar bears also use the barrier islands to rest, den, and provide access to other feeding locations.

The proposed Northstar project occurs within the range of known polar bear denning (Amstrup, 1995:259; USDOI, FWS, 1995: Figures A-36 and A-38). Although there are no documented dens in the Northstar Unit, or along the coastal areas between the Kuparuk and Putuligayuk Rivers, potential denning habitat occurs on Long Island, and along or on coastal and riverine bluffs. Current levels of industrial activity and disturbances in the area preclude the use of some areas by denning females. Polar bears represent an important subsistence and cultural resource for local residents.

**Onshore Ecosystem:** Common vegetation communities range from dry tundras to moist to aquatic tundra, with grasses and sedges dominating the species composition of most communities. Small variations in topography due to permafrost polygon formation (Section 5.3.1), pingos, or river banks create microhabitats supporting small woody shrubs and lichens which favor the drier, higher areas. Habitats considered high value include: ponds with *Arctophila fulva* (an emergent grass), which is heavily used by waterfowl during the breeding, molting, and brood-rearing periods; islands in the Sagavanirktok River Delta used for nesting by snow geese; coastal saline marshes used by brant, snow geese, and shorebirds for feeding and brood-rearing; and freshwater streams deep enough (greater than 6 ft [1.8 m]) to remain unfrozen during winter, which are essential overwintering habitats for resident and anadromous fish.

Most birds on the Arctic Coastal Plain are migratory, traveling from as far away as South America to breed during the brief Arctic summer. Seasonal abundance varies from an occasional raven, ptarmigan, gull, or snowy owl in winter, to an influx of hundreds of thousands of waterfowl and shorebirds from May through September (Section 6.7). Waterbirds, such as snow geese, tundra swans, and loons, are the most conspicuous. King eiders, spectacled eiders (a threatened species), and oldsquaw nest on the tundra, and then congregate in coastal waters for molt and migration. Although waterfowl and shorebirds occur in low densities across the tundra during the nesting season, large numbers congregate or stage in relatively small areas during migration, which makes them vulnerable to a single disturbance event. Birds are major consumers of energy and are important links in arctic foods webs. Waterfowl are also a food resource for humans, providing an important subsistence role for local residents (Section 7.3).

Caribou are year-round inhabitants of the Arctic Coastal Plain although most winter in the Brooks Range. Pregnant cows move from the Brooks Range foothills to spring calving grounds near the coast to avoid predators during the vulnerable calving period. The remainder of the herd moves toward the coast in late spring. Warm temperatures in midsummer result in mosquito and oestrid fly hatching; caribou are so harassed by mosquitoes and flies that the relief provided by coastal winds and cooler temperatures is considered critical to their health (Section 6.8). Grizzly bears appear in small numbers on the coastal plain in late spring, preying on Arctic ground squirrels and caribou calves, as well as consuming various roots and berries. Arctic and red foxes are major predators on bird eggs and lemmings. Both bears and foxes are attracted to human activities, and may scavenge garbage as an additional food source. Many of these mammals are taken by local residents, with caribou serving as a major food item (Section 7.3).

#### *3.4.1.3 Human Environment*

The North Slope Borough (NSB) is the largest, northernmost, home rule municipal government in Alaska, covering approximately 88,000 square miles (227,920 square km). In 1993, the NSB had a recorded population of 6,538 residents living in eight permanent communities. The majority of residents are indigenous Inupiat Eskimos. The community of Barrow, the seat of government of the NSB, is home to approximately 3,900 residents and is located just southwest of Point Barrow on the Chukchi Sea coast. Two other North Slope communities with direct access to the Alaskan Beaufort Sea are Nuiqsut, located approximately 16 miles (26 km) inland on the Colville River, home to approximately 400 residents, and Kaktovik, located on Barter Island in the eastern Alaskan Beaufort Sea, home to approximately 225 residents. There is no permanent road access to these communities, although occasional construction of an ice road provides a connection between Nuiqsut and the industrial complex at Deadhorse. Residents travel between communities and to subsistence harvest sites by boat, airplane, and snowmachine as conditions permit.

The Alaskan Beaufort Sea and adjacent land area have been the home of the Inupiat people for thousands of years. Numerous cultural and historical resource sites on barrier islands and along the coastline and rivers of the North Slope are evidence of the Inupiat's long-term, continuous use of the region. Local residents of the North Slope have retained a largely traditional, subsistence-based lifestyle. They participate in the harvest of subsistence resources and related cultural activities throughout the year (Section 7.3). Harvesting, processing, and distributing bowhead whale is particularly important to the Inupiat culture. Subsistence activities are a significant part of the overall North Slope economy. The cash economy is derived to a great extent from taxation of oil industry facilities by the NSB, and by employment in government services. The majority of wage-earning North Slope residents are employed by the NSB, the NSB School District, village governments, regional and village corporations created by the Alaska Native Claims Settlement Act, or the oil industry.

The James B. Dalton Highway (Haul Road) connecting Deadhorse to Fairbanks, is the only road to the North Slope. It was constructed as an industrial service road, but has recently been opened to travel by the general public. Regularly scheduled commercial air service is the primary means of passenger and cargo transportation to and within the NSB. Barrow and Deadhorse airports and the airstrip maintained by ARCO within the Prudhoe Bay oil field are the only airstrips capable of handling large aircraft. A short open water season on the Chukchi and Alaskan Beaufort Seas allows limited annual barge transport of materials and fuel to coastal communities and Deadhorse.

### 3.4.2 Technological Options Applicable to Offshore Oil and Gas Operations

#### *3.4.2.1 Overview of Oil and Gas Activities*

The identification and development of offshore oil and gas resources involve a series of distinct activities. These activities are generally categorized into two phases, exploration and development/production. Specific activities include those summarized below.

**Exploration:**

- Seismic Surveys - Exploratory seismic surveys are conducted to collect data used to interpret subsurface geology. (These surveys often occur during production also.)

- Exploration Drilling - Once promising geologic structures are identified, exploration drilling is conducted to confirm the presence of recoverable oil and gas resources, and to evaluate the potential volume of oil that could be produced. Several wells are typically required to confirm a discovery and provide sufficient data to prepare a development/production plan.

**Development/Production:**

- Development/Production Drilling - This activity typically involves the installation of several oil production wells. In addition, reservoir development may require water or gas injection wells. Several wells may be drilled from a single location using directional drilling technology. Operation of production wells involves routine well maintenance procedures, some of which require a workover rig (a type of drilling).

- Oil and Gas Processing - Processing facilities may be located at the production site if sufficient space is available, or they may be located at a distant site. Sometimes the produced fluids are only partially separated into oil, gas, and produced water components at the production site prior to transport to offsite processing facilities for final separation.

· Transportation of Produced Fluids - Produced fluids (oil, gas, and water) may be transported from offshore sites by pipeline, marine tankers, or barges during open water, and pipelines or trucks during winter. Pipelines, railroads, and trucks may be used year-round at onshore locations. Existing offshore drilling and production facilities in the Prudhoe Bay area are connected to shore by gravel causeways which protect pipelines from sea ice hazards. Buried subsea pipelines have never been used in the Alaskan Beaufort Sea, but a buried subsea pipeline was installed once in the Drake gas field in the Canadian Arctic (Section 3.4.2.7).

· Facility Decommissioning and Abandonment - When a production facility is no longer economically viable, it is decommissioned. Wells are plugged and surface structures may be removed. Facilities may be reused in place, transported for use at another location, removed for salvage or disposal, or cleaned and prepared for abandonment in place.

In addition to the development of oil and gas facilities, construction and operation of these facilities frequently results in the need for development of gravel mines, freshwater sources, roadways, airstrips/heliports, and waste collection and disposal systems.

A brief description of oil and gas technologies and facilities that may be applicable to development in the Alaskan Beaufort Sea is presented below.

### *3.4.2.2 Seismic Surveys*

Seismic surveys are conducted to collect subsurface geologic data. Although primarily associated with exploration, seismic surveys are sometimes conducted in producing fields to provide data used to refine field development plans. In the Arctic, offshore seismic surveys are conducted during open water periods (typically August and September) or winter time (February through April). Open water surveys are conducted by a survey vessel equipped with an air gun and a towed array of hydrophones. The air gun uses compressed air to create a sound wave that penetrates the seafloor and is reflected by different rock layers. Hydrophones record these reflected sound waves, and the data collected is used to develop a “picture” of the geologic formation under the seafloor. Support vessels are often used for logistical support and ice management activities.

During the winter (February through April), seismic surveys are conducted from the ice surface. The sound source for these surveys is a large vibrating plate which is mounted on a wheeled vehicle. Geophones are placed on the ice surface and record reflected sound waves in the same manner as the hydrophones used during open water season surveys. There are no further seismic activities currently planned for the Northstar Unit; therefore, this EIS does not address seismic activities specific to the Northstar Unit.

### *3.4.2.3 Oil and Gas Drilling Methods*

Characteristics such as water depth, distance from shore, reservoir depth below the seafloor, reservoir thickness, degree of faulting, reservoir permeability and porosity, and the overall areal extent of the reservoir determine the drilling options for oil and gas development. There are two categories of drilling methods for recovering oil and gas reserves: 1) conventional vertical drilling in which the well is drilled straight down, and 2) directional drilling in which the well is drilled at an angle. As directional drilling techniques are improved to make longer horizontal divergences from the top to the bottom of the well possible, the term “extended reach” drilling is sometimes used. For convenience, “directional drilling” in this document will include all angled, extended reach, or stepped out drilling methods.

Reservoir production from a conventional vertical well is limited to the portion of the reservoir located beneath the wellhead. Multiple surface locations would be required to develop a reservoir that has a large areal extent using conventional vertical drilling. In contrast, direction drilling allows for access to multiple bottom hole locations from a single surface facility. A directional well can produce more than a vertical well because it intersects a greater portion of the reservoir as it passes through the producing formation at an angle. For an offshore reservoir, many surface structures are not practical for cost, logistical, safety, and environmental reasons. Conventional vertical drilling is not preferred onshore or offshore in the Alaskan Arctic.

Directional wells typically cost approximately two to three times more than a conventional vertical well. Much of the additional cost is associated with the equipment and data verification required to ensure that directional wells intersect the desired target locations within the reservoir. Directional wells also take more time to drill because they are often much longer than vertical wells.

The horizontal reach of a directional well may be limited by the substrate and borehole angle required to reach the intended location. The longest directional well drilled on the North Slope is approximately 3.9 miles (6.3 km) at the Niakuk field (Nelson, 1996:11). The vertical portion of the well was drilled to a depth of 1.8 miles (2.9 km) and a departure from vertical was drilled for 3.4 miles (5.5 km). The longest directional well drilled in the world to date is approximately 5 miles (8 km) at Wytch Farm in the United Kingdom (Headden, 1995:40[2]). In this case, the vertical depth was 1 mile (1.6 km) and the horizontal departure was 4.2 miles (6.8 km). Advances in drilling technology have resulted in the progressive increase of the reach of directional drilling over time (ADNR, 1997:5-9). The ability to "reach" extended distances from the surface drill site varies from one project to another. Reservoir geology and depth may limit the well "reach" to distances much less than 4 miles (6.4 km) in some cases.

The location and characteristics of the oil and gas reservoir and directional drilling technology limit the range of potential surface drilling sites. The range of locations for surface facilities may include onshore, on existing offshore islands (natural or manmade), or a new offshore location.

#### *3.4.2.4 Offshore Production Structures*

Selection of drilling and/or production structure(s) is based on the site-specific environment of the offshore reservoir and project economics. In addition, oil recovery and processing methods (Sections 3.4.2.5 and 3.4.2.6), options for transportation of product (Section 3.4.2.7), and relationships between onshore and offshore facilities influence structure location. This section presents a brief description of components that may be a part of a drilling and/or production facility, and a comparison of the following factors for drilling and production structure options:

- Depth of water in which it can be used.
- Structural stability to withstand ice forces known to occur at the offshore site.
- Durability.
- Noise propagation characteristics.
- Space available for facilities needed.
- Cost.

**Components of Production Facilities:**

<u>Drilling Rig and Associated Equipment</u>: The drilling rig contains power generation units, a drilling mud system (tanks, cuttings removal screens, pumps), a cementing system, and a storage area for drill pipe.

Additional storage space is required for drilling mud, cement, and well casing.

Oil/Gas/Water Separator System: Usually one to three multi-phase bulk oil separators are used to decrease the pressure of produced fluids and remove natural gas and water to produce stabilized sales quality crude oil. Separators are located on the offshore structure and/or onshore sites, depending on how much processing is done at the offshore production site.

Water Treatment and Injection System: Water produced with the oil is routed to a clarification system consisting of a series of vessels that separate oil from water by gravity, electrical, or centrifugal force. Clarified water is pumped to a disposal well, injection well, or to a pipeline for transport to another location.

Gas Dehydration and Compression System: Gas removed from produced reservoir fluids is routed to coolers that use air and/or seawater for cooling. Cooled gas flows into vessels that separate the remaining water from the gas. Natural gas liquids also may be separated in this process. Low pressure gases are compressed by a series of turbine-driven and/or electric-driven compressors, and further dehydrated with chemicals that absorb water remaining in the gas. The gas may be injected to the reservoir (for gas cycling or gas lift), used on site as fuel, or transported by pipeline to another location.

Seawater Systems: Seawater is used for fire suppression, for waterflood, and to supply potable water. Seawater for waterflood may require deaeration and chemical treatment to match the characteristics of the naturally-occurring reservoir water prior to injection into the reservoir. Seawater is also sometimes used to cool processing equipment. Outfalls for wastewater discharges may be required.

Emergency Flare: Flares are tall structures with a small stream of gas feeding a continuous pilot flame. This safety system protects processing systems during startups and shutdowns, as well as provides emergency gas pressure relief. The flare burns gas to prevent its release to the atmosphere.

Chemical Treatments: Chemical storage systems include tanks and small electric-driven pumps to inject chemicals such as emulsion breakers, corrosion inhibitors, biocides, and anti-foaming agents into producing wells and pipelines.

Electric Power Generation: Electricity is provided by at least one main and one standby emergency generator.

Fire Suppression: The main components of the fire suppression system are a water storage tank, pump, and distribution piping.

Other facilities that would be located on a manned production structure include: offices and a control room, a potable water system, a wastewater treatment system, heating and cooling systems, storage and shop areas, and living quarters. Ship docking facilities and a helicopter landing area are likely to be needed for either a manned, or unmanned structure.

**Islands:** Because a natural island modified to support drilling and/or production facilities would function similar to an artificial island, differentiation will not be made here. Ice islands and floating structures are discussed together because of their similar seasonal limitations.

Manmade gravel islands are constructed by placing gravel on the seafloor until the mounded gravel is above sea level. After an island is created, slope protection may be used to prevent erosion by waves and moving ice. Historically, the practical limit of water depth for a manmade gravel island appears to be about 65 ft (20 m) (Figure 3-1) because of the logistical and economic constraints related to the amount of gravel required to create an island in deeper water (Masterson, 1991:17). However, in theory, the water depth for gravel islands is not limited. The location of the source material for the island and hauling time/distance greatly influence its cost. Re-use of an existing island would reduce the amount of material even if additional material is needed to enlarge the island or repair damage caused by erosion. Usually at least some of the material would be brought from a site on land because sediments dredged from the seafloor tend to be too soft to support facilities. However, some areas of the Alaskan Beaufort Sea floor do have appropriate material for island construction. Material from an abandoned (or natural) island also could be moved to the desired location. A recent example is the reuse of approximately 45,250 cubic yards (34,600 cubic meters) of gravel from NW Milne Island to enlarge F Pad (Milne Point unit) into marine waters. When the distance to a material source is too great and the cost of hauling is too high, another type of structure would be considered.

Gravel islands typically have side slope ratios of approximately 1:3 (vertical:horizontal), with the island surface 10 to 23 ft (3 to 7 m) above sea level (Masterson et al., 1991:23). Some islands were constructed with side slopes as flat as 1:20, resulting in a beach-like slope structure that can be washed away without affecting the integrity of the island's working surface. Sandbags, interlocking concrete blocks or mats, or steel walls may be used to help protect island slopes from wave and ice erosion. Slope protection is likely to be required for all long-term use of islands. In contrast to other structures (see below), gravel islands are relatively easy and inexpensive to repair by replacing or reshaping gravel and slope protection, as necessary. Gravel islands can withstand ice movements because they are an extension of the seafloor and the base area is larger than the working surface. This provides resistance to sliding (lateral movement) greater than other structures. Construction costs for gravel islands typically range from $10 to $40 million, depending on size of the island and water depth (Masterson et al., 1991:25).

Gravel, sand, and other earthen materials absorb sounds and particularly dampen higher frequency noise. As discussed in Chapter 9, sounds from an island are transmitted by structural vibrations through the island material into the water. Measurement of noise of industrial activities on a gravel island in the Alaskan Beaufort Sea demonstrated greater attenuation of noise relative to other types of structures (Davis et al., 1985; Johnson et al., 1986; Richardson et al., 1995). Although sound propagation is site specific, gravel islands are generally expected to dampen more noise than other types of structures.

A gravel island structure:

- Is economically and logistically limited to about 65 ft (20 m) water depths.
- Can withstand high lateral ice forces without movement or damage.
- Is subject to erosion, but is easily repairable.

- Is expected to have the greatest noise dampening of all structure types.
- Is almost unlimited in design size and flexibility of shape.
- In most cases, is less expensive than other structures.

**Mobile Bottom-Founded Structures:** Mobile, bottom-founded structures are those that rest on the seafloor, but can be floated and towed to different locations. Designs for mobile, bottom-founded structures were developed to conduct offshore exploratory drilling in the Arctic during the 1980s. Several different one-of-a-kind structures of this type were used and remain in Arctic or northern waters. These are described below.

<u>Caisson Islands</u>: One-of-a-kind structures, such as the Caisson Retained Island (CRI) and the concrete caisson island (Tarsiut), were designed to increase slope protection and decrease gravel fill requirements over a conventional gravel island. This is particularly important when material is unavailable, unsuitable, or haul distances are long. The CRI was constructed in 1982 and consists of eight steel caissons linked together by cables forming a ring 384 ft (117 m) across the bottom with 302 ft (92 m) of working deck width at the top. The caissons are subdivided into 10 ballast tanks, two fuel tanks, machinery spaces, and a control room (Arctic Transportation Ltd., 1995:4). The CRI is ballasted with seawater to rest on the seafloor or a prepared gravel pad. The inner ring is filled with sand or gravel. The CRI is designed to operate in water depths between 11.5 and 66 ft (3.5 to 20.1 m). In more than 20 ft (6 m) of water depth, a gravel pad or berm is needed. Equipment located on the CRI likely would include: a rotary table drilling rig, drilling mud pumps and mud mixing equipment, a cementing unit, blowout preventor system and associated manifolds, diesel-powered generators, air compressors, a domestic water treatment system, and facilities to accommodate staff.

The CRI was used for oil and gas exploration and it is not designed for production activities. The CRI does not have space for numerous wells and equipment needed for production.

The Tarsiut Caisson Island, built in 1986 for use in the Canadian Beaufort Sea, is constructed of four concrete caissons and installed on a submerged berm in water 70 ft (21.3 m) deep (Han-Padron, 1985:5-11). The hexagonal center core is filled with sand or gravel and the working deck area is approximately 330 ft (101 m) across. Relocating the Tarsiut would require removing, resetting, and connecting the caissons at a new site. This has never been attempted and would be difficult because the caissons are ballasted with sand, rather than water (Masterson et al., 1991:11). Equipment located on the Tarsiut likely would include: a rotary table drilling rig, drilling mud pumps and mud mixing equipment, a cementing unit, blowout preventor system and associated manifolds, diesel powered generators, air compressors, a domestic water treatment system, and facilities to accommodate staff.

The caisson island designs:

- Are limited to 11.5- to 70-ft (3.5 to 21 m) water depths.
- Have demonstrated stability in heavy ice.
- Have demonstrated durability and currently are in good condition.
- Have a fixed size working area that would need to be restructured to accommodate production facilities and a larger number of wells.

· Would reduce gravel costs, but would require extensive modifications to accommodate the needs of a long-term development/production program.

Concrete Island Drilling Structure (CIDS): The CIDS consists of a steel base that rests on the seafloor and a concrete unit that extends through the surface water/ice zone (Figure 3-3). The CIDS has drilled four exploration wells in the Alaskan Beaufort Sea. None of these wells were drilled in the project area shown on Figure 3-1. Three wells were drilled off of Cape Halkett, approximately 80 miles (128.7 km) west of the Northstar Unit (one in 1984 in 49 ft [15 m] of water, another in 1985 in 49 ft [15 m] of water, and a third in 1985 in 50 ft [15.2 m] of water). A well was drilled in 1997 in approximately 50 ft (15.2 m) of water in Camden Bay, approximately 75 miles (120.6 km) east of the Northstar Unit (D. Choromanski-Pers. Comm., 1998). Operational water depths for the CIDS range from 35 to 55 ft (10.7 to 16.8 m). The working deck area measures 291 by 274 ft (88.6 by 83.5 m), and the base is 312 by 295 ft (95 by 90 m). Equipment located on the CIDS includes: a rotary table drilling rig, drilling mud pumps and mud mixing equipment, a cementing unit, a blow-out preventor system and associated manifolds, diesel-powered electric generators, cranes, air compressors, a domestic water treatment system, and facilities to accommodate up to 94 staff.

The CIDS was not designed for oil and gas development/production activities; however, the owners have proposed to modify CIDS to accommodate such facilities. Proposed modifications include reconstructing the current drilling equipment layout, adding production equipment, allowing space for 22 wells, and an additional deck for a maximum of 35 wells (Global, 1995: Section 9:1). Limits on production capacity were not provided by the vendor. Long-term maintenance requirements are unknown, but may require transport to dry dock facilities away from the oil production area.

The CIDS:

· Is limited to 35- to 55-ft (10.7 to 16.8 m) water depths.
· Has demonstrated stability in heavy ice.
· Has demonstrated durability and currently is in good condition.
· Has a fixed size working area that could be restructured to accommodate production facilities and 22 to 35 wells.
· Requires modifications in dry dock costing approximately $70-75 million.

Mobile Arctic Caisson (Molikpaq): The Molikpaq is an eight-sided steel caisson constructed as a continuous ring, creating a hollow center which is filled with sand or gravel and a working top deck (Figure 3-4). The caisson has outer dimensions of approximately 366 ft (111.5 m) per side at the base and approximately 241 ft (73.4 m) per side on the working deck. The caisson is divided into 12 ballast compartments filled with seawater.

The Molikpaq began operations in 1984 and has drilled 10 wells in the Canadian Beaufort Sea (Gulf, 1995:1). It is designed to drill in water depths ranging between 30 and 130 ft (9 to 39.6 m) (BPXA, 1996:6-4). For water depths over 69 ft (21 m) it requires a pad to raise the bottom surface. Equipment located on the Molikpaq includes: a rotary table drilling rig, drilling mud pumps and mud mixing equipment, a cementing unit, a blow-out preventor system and associated manifolds, diesel-powered electric generators, cranes, air compressors, a domestic water treatment system, and facilities to accommodate 104 staff.

The Molikpaq was not designed to support oil and gas development/production activities. However, the owners have proposed to modify the Molikpaq to accommodate such facilities. Modifications that have been proposed would be to reconstruct the current drilling equipment layout to add the necessary production equipment and allow space for 24 to 40 wells. Production capacity would range from 65,000 to 120,000 barrels/day oil, 110 to 180 million standard cubic feet per day of natural gas, and 100,000 to 180,000 barrels/day water. Maintenance requirements are unknown.

The Molikpaq:

- Is limited to 30- to 130-ft (9 to 39.6 m) water depths.
- Has demonstrated stability in heavy ice.
- Has demonstrated durability and is in good condition.
- Has a fixed size working area that could be restructured to accommodate production facilities and 40 wells.
- Requires modifications to accommodate a long-term development/production program with modification costs expected to be between $85 and 112 million.

<u>Single Steel Drilling Caisson (SSDC)</u>: The SSDC is a modified, very large crude oil carrier (super tanker) that conducts exploratory drilling operations in open water and ice (Figure 3-5). The SSDC has been previously used to drill exploration wells in the Alaskan Beaufort Sea; however, only one location is in the project area shown on Figure 3-1. Other locations where the SSDC has been used in the Alaskan Beaufort Sea outside the project area include two wells drilled off Cape Halkett, approximately 80 miles (128.7 km) west of the Northstar Unit. One of these was drilled in 1990 in 50 ft (15.2 m) of water, and another was drilled in 1991 in 55 ft (16.7 m) of water. Additionally, one well was drilled in 1987 in 66 ft (20 m) of water offshore of the Beaufort Lagoon, approximately 150 miles (241 km) east of the Northstar Unit (D. Choromanski-Pers. Comm., 1998). Operational water depths initially ranged from 25 to 70 ft (7.6 to 21.3 m); however, a steel platform was added in 1985 which allows the structure to operate in water depths to 100 ft (30.5 m) (CANMAR, 1994:4). Drilling in 80 to 100 ft (24.3 to 30.5 m) of water requires construction of a gravel berm in addition to the steel platform. The working deck of the SSDC is approximately 664 ft (202.4 m) long by 174 ft (53 m) wide.

Figure 3-3 (page 1 of 2)

Figure 3-3 (page 2 of 2)

Figure 3-4 (page 1 of 2)

Figure 3-4 (page 2 of 2)

Figure 3-5 (page 1 of 2)

Figure 3-5 (page 2 of 2)

The SSDC began exploratory drilling in the Alaskan Beaufort Sea in the winter of 1982/1983. Two exploratory wells were drilled from a prepared gravel berm in 100 ft (30.5 m) of water outside the landfast ice zone (Masterson et al., 1991:9). Equipment located on the SSDC includes: a rotary table drilling rig, drilling mud pumps and mud mixing equipment, a cementing unit, a blowout preventor system and associated manifolds, diesel-powered electric generators, an extended flow well test separator, crude oil storage capacity of approximately 700,000 barrels, cranes, air compressors, a domestic water treatment system, and facilities to accommodate 93 staff.

The SSDC was not designed for oil and gas development/production activities; however, the owners proposed to modify the SSDC to accommodate drilling and production facilities. Proposed modifications include reconstructing the current drilling equipment layout to add production equipment and allow space for 30 to 40 wells. Production capacity ranges from 40,000 to 50,000 barrels/day oil, 1 to 4 million standard cubic feet per day of natural gas, 20,000 barrels/day water, and an oil storage capacity of 625,000 barrels of crude in the steel platform (CANMAR, 1995:31-34). Long-term maintenance requirements are unknown.

The SSDC:

- Is limited to 25- to 100-ft (7.6 to 30.5 m) water depths.
- Has demonstrated stability in heavy ice.
- Has demonstrated durability and currently is in good condition.
- Has a fixed size working area that could be restructured to accommodate production facilities and 40 wells.
- Would require modifications to accommodate a long-term development/production program, with modification costs estimated to be approximately $113 million.

These bottom-founded structures or others that could be designed and constructed to meet specific project needs are feasible options within the limits discussed for drilling and production structures in the Alaskan Beaufort Sea. The structures have a record of success in withstanding sea ice and other cold weather operating conditions.

**Subsea and Subterranean Structures:** In areas where ice movements or gouging of the seafloor would endanger an exposed structure, facilities could be placed deep enough below the seafloor to prevent damage. Construction of such facilities would be expensive, and would generally require a large reservoir or special site conditions to justify this expense.

A subsea cavern is similar in design to an underground mine. A cavern would likely have an access tunnel from land which would also be used for removal of excavated material and for transport of produced oil and gas to shore. Considerations for using a subsea cavern structure include distance of the reservoir from shore (i.e., length of the tunnel), heat transfer to the surrounding permafrost, disposal of excavated soils, ventilation of hazardous and flammable gases, and emergency evacuation of personnel.

Subsea silos, similar in concept to underground missile silos, have been considered to develop the Kuvlum reservoir in the Alaskan Beaufort Sea. The Kuvlum reservoir is located in the shear ice zone about 12 miles (19.3 km) offshore in approximately 105 ft (32 m) of water. The conceptual design includes produced oil and gas reaching shore through a trenched pipeline. The silo design depth is approximately 40 ft (12 m) below the seafloor and 20 to 24 ft (6 to 7.3 m) in diameter to allow well servicing and maintenance (MBC, 1996:26). The Kuvlum design includes a cover plate over each silo near the seafloor surface for additional protection of wellheads and production equipment from ice. Plans for this development or other silos in the Alaskan Beaufort Sea are not anticipated in the near future.

A subsea cavern or silo:

- Can be constructed in water depths as great as 200 ft (61 m).
- Could be protected from ice damage.
- Would not be subjected to erosion or other damage.
- Could be designed for any size working area.
- Would have very high costs.

**Subsea Templates:** Seafloor templates, which rest on the surface of the seafloor, are used in many offshore regions as a drilling guide and to house wellheads. Drilling equipment is positioned over a template and wells are drilled and brought into production using pipelines or flexible, steel-reinforced (umbilical) hoses to connect the template to oil and gas processing facilities. These pipelines carry produced fluids from the wellheads to processing facilities. Templates are used in deep water with nearby floating production and drilling structures. A seafloor template with multiple wells is more economical than single well templates, but also increases the size of the structure that rests on the seafloor. The largest operating multi-well seafloor template is in the Gulf of Mexico; it measures approximately 118 by 75 by 56 ft (36 by 23 by 17 m) (length by width by height) and houses 10 well slots (Abbott et al., 1995:314 and 315).

A variation on the conventional subsea template has been used off the east coast of Russia near Sakhalin Island in a severe ice environment. A four well template was placed in a seafloor excavation and protected by 36 ft (11 m) high steel caissons and a lid buried in the seafloor. This subsea caisson production system was developed for gas production. A buried subsea pipeline transports produced gas from the subsea caisson production system to onshore facilities for processing and distribution (J.P. Kenny, 1992:1-4).

Seafloor templates could be used in water depths greater than 200 ft (61 m) in the Alaskan Beaufort Sea, where ice grounding or gouging do not occur. At these depths, a floating vessel would be used to drill the wells. It may take a full 2- to 3-month summer season to drill a single well. In deep water situations, this combination may be feasible for development/production in the Alaskan Beaufort Sea.

A subsea template system:

- Could be used in water depths greater than 200 ft (61 m).
- Design would not have to consider ice forces on the bottom.
- Would not be subjected to erosion or other damage.
- Would be a fairly quiet facility, but would transmit noise directly to the water.
- Size could be adjusted to meet a wide range of production objectives.

- Would have moderate to high costs.

**Floating Drilling Structures (Seasonal Use Structures):** Floating drilling structures have limited usefulness in the Arctic unless conventional designs are modified for ice protection. Even with modifications, a floating structure is not considered suitable for year-round development/production activities because it could be moved and/or damaged by ice. Seasonal drilling and workover activities in combination with a seafloor template or subsea silo enclosed template are potential production-related uses of floating drilling structures. These could be used during open water periods and in over-ice applications when used in conjunction with ice islands. In general, floating structures are not suitable for year-round use as a development and production facility.

<u>Jackup Drilling Platform</u>: Conventional jackup drilling platforms are towed and positioned over a specific drilling location. Three legs are lowered to the sea floor to stabilize the superstructure, which is then raised out of the water. Jackup platforms have been used to support exploratory drilling activities in waters less than 100 ft (30.5 m) deep in open water conditions.

<u>Semi-Submersible Drilling Vessels</u>: Semi-submersible drilling vessels are self-powered or towed steel-hulled platforms that are positioned over a specific drilling location. Their position in the water is controlled either by a dynamic positioning system or by an anchor mooring system. Semi-submersibles can operate in waters between 100 and 1,000 ft (30.5 and 305 m) deep in open water conditions.

<u>Ice Islands</u>: Ice islands are created by pumping seawater onto the frozen sea ice sheet. The water freezes in layers until the ice is grounded onto the seafloor or is thick enough to accommodate the weight of a drilling rig and associated equipment. Ice islands would be used for exploration drilling for only one winter because they melt and lose structural integrity in spring and summer months when ambient air temperatures are above freezing.

<u>Drillships</u>: Conventional drillships are self-powered, steel-hulled platforms that are positioned over a specific drilling location. Their position in the water is controlled either by a dynamic positioning system or by an anchor mooring system. Drillships have been supporting exploratory drilling operations in waters of the Alaskan Beaufort Sea since 1976. Drillships can operate in waters between 100 and 1,000 ft (30.5 and 305 m) deep in open water conditions.

<u>Conical Drilling Unit (Kulluk)</u>: The Kulluk is a one-of-a-kind floating exploration drilling vessel designed for extended season arctic operations in light to moderate ice conditions. It is towed to and positioned over a drilling location. The double-walled, inward-sloping hull is in the form of an inverted cone, 265 ft (80.8 m) in diameter. The cone flares at the bottom, causing light to moderate ice to break downward and away from the hull. The Kulluk is held in position by 12 radially-deployed mooring lines in water depths of 60 to 600 ft (18 to 183 m) (CANMAR, 1994:18). The Kulluk has drilled one exploration well in the Alaskan Beaufort Sea. The operating range of the Kulluk is considered practical in up to 328 ft (100 m) water depths (Masterson et al., 1991:12).

Except for ice islands, these structures are not designed to operate in sea ice and are limited to open water or light ice conditions during the summer; ice islands are usable only during winter. These structures are not suitable for long-term development/production activities in the Beaufort Sea; however, they could be used for drilling on a seasonal basis as drilling support facilities for a seafloor or silo template installation. Because they are steel-hulled structures (except ice islands), these are expected to transmit more drilling and operational noise than other types of structures. The amount of noise would increase if ice-breaking vessels were used as part of an ice management program to protect the drilling structure in moderate ice conditions to extend the drilling season.

#### *3.4.2.5 Oil and Gas Recovery*

A variety of technologies, ranging from those relatively unchanged for more than a century to modern state-of-the-art technologies, are used for oil and gas recovery. These technologies are usually referred to as primary, secondary, or enhanced (tertiary) recovery.

**Primary Recovery:** Primary recovery uses only the reservoir's natural pressure to force crude oil from the underground reservoir to the surface. As the reservoir is depleted, the reservoir's pressure drops, resulting in a decline in crude oil recovery rates. Primary recovery was used with the earliest oil wells and is still used today when reservoir pressures are sufficient to force reservoir fluids to the surface. Primary recovery by itself results in an average recovery of only 5% to 20% of a reservoir. Some reservoir developments employ primary recovery during early reservoir development/production, then add a secondary recovery method for continued production.

Primary recovery is a reasonable option for oil and gas development/production in some situations in the Alaskan Beaufort Sea. For a fairly large reservoir, or one that would have too many difficulties in implementing pressure enhancement, this could be the best option. A deep water site could be developed with sea floor templates and primary recovery using a minimal investment in facilities.

**Secondary Recovery:** Secondary recovery options are designed to improve oil recovery from the reservoir. This is accomplished by boosting or maintaining reservoir pressure or by lifting fluids in individual wells. Secondary recovery options include injecting gas or water into the reservoir to maintain reservoir pressure as oil, gas, and water are produced. These secondary recovery methods include gas lift, reservoir maintenance with gas (gas cycling), reservoir maintenance with water injection, and waterflood. Use of secondary oil recovery options depends upon individual reservoir characteristics, such as pressures, water and gas volumes, geometry, depth, fluid properties, formation permeability, and porosity.

Availability of water or gas from another source is a factor in choosing an appropriate secondary oil recovery technology. A combination of recovery methods may be used, depending upon reservoir characteristics. Therefore, each reservoir development is evaluated individually for the best application of secondary oil recovery technology.

<u>Gas Lift</u>: Gas lift involves injecting natural gas at high pressure, usually several thousand pounds per square inch, to introduce small bubbles into the oil/water column in the well. The gas bubbles lighten well fluids, allowing them to rise to the surface easily. Gas lift is effective particularly if the reservoir

contains heavy, thick oil or if it has high water content. Gas lift requires a gas supply, either from the producing reservoir or an external gas source. The amount of gas needed is small relative to gas cycling (below) and usually can be supplied by the producing reservoir. Gas compression, cooling, and dehydration are required to implement gas lift.

Gas lift:

- Is useful for heavy, viscous oils, or oils with high water content.
- Is applicable on a single well basis.
- Can be integrated with other secondary or enhanced oil recovery methods.
- Requires gas compression and dehydration.
- Requires air coolers or a cooling water source (may have subsequent warm water discharge).

<u>Reservoir Pressure Maintenance with Gas (Gas Cycling)</u>: Gas cycling involves reinjecting natural gas through dedicated injection wells into a reservoir's overlying gas layer (the reservoir's gas cap) or into the oil producing zone. The reinjected gas preserves or enhances reservoir pressure, which then allows greater volumes of oil to be recovered. The gas supply requires compression, cooling, and dehydration. The pressure of the gas reinjected into the reservoir must be higher than the existing reservoir pressure, typically 3,500 to 5,000 pounds per square inch.

Gas cycling is effective in reservoirs that have a natural gas cap or that can produce a substantial amount of gas. Because gas cycling requires 1 to 1.5 times the amount of gas normally produced daily, an external, supplemental natural gas source must be available. Typical reserve recovery rates range from 45% to 65%.

Gas cycling:

- Is useful in reservoirs with a natural gas cap or with a large volume of gas.
- Is applicable on a reservoir-wide basis via dedicated injection wells.
- Can be integrated with other secondary or enhanced oil recovery methods.
- Is useful for light oils that flow easily.
- Requires a natural gas cap or substantial amounts of gas in the crude oil.
- Requires gas compression and dehydration equipment.
- Requires supplemental gas supply.
- Requires air coolers or a cooling water source (may have subsequent warm water discharge).

<u>Reservoir Pressure Maintenance with Water Injection</u>: Many oil/gas reservoirs have aquifers beneath the oil reservoir and water injected into the underlying aquifer causes upward pressure on the oil layer. This pressure forces the oil to continue flowing to production wells. Some of the water injected may be produced water (i.e., water separated from reservoir fluids). Generally, one to two times the amount of fluid produced from the reservoir is required for water injection. Water from another source, such as seawater, can be treated and injected along with produced water to maintain reservoir pressure. Water is injected at pressures above existing reservoir pressure through dedicated water injection wells.

Poor water quality can damage an injection well, resulting in the need for extensive repair and maintenance. Treatment of produced water and seawater may consist of separation of oil from water, addition of chemicals, removal of air and solids, and compression. Typical water injection recovery rates are 35% to 45% of reserves.

Water injection:

- Is useful when large aquifers are present beneath the oil reservoir.
- Is applicable on a reservoir-wide basis via dedicated injection wells.
- Can be integrated with other secondary or enhanced oil recovery methods.
- Requires treatment of produced water and/or seawater.
- Can damage injection wells if water quality is poor.
- May require large turbine-driven or multi-stage pump systems.

<u>Waterflood</u>: Waterflooding involves injecting treated produced water or seawater directly into the oil reservoir through dedicated injection wells. Water is injected in a specific pattern, to flush oil toward oil production wells. Injection wells are located in geometrical patterns around producing wells or injected at the boundary of the reservoir. Uniform reservoir permeability is essential for a successful waterflood.

During the start of a waterflood program, water use would be approximately two barrels of water per barrel of oil produced. Ultimately, the volume of water is in the range of 150% to 170% of the total produced fluids. If available, seawater is the best choice for initial waterflooding until formation water is produced at a rate high enough to supply a long-term waterflood program. Seawater also can be used as the sole supply.

Poor water quality can damage an injection well irreparably or result in expensive workover costs. Treatment and injection equipment requirements for waterflood are similar to water injection. The size and quantity of treatment and injection equipment depends upon the amount of oil/water produced and treated for injection, and the characteristics of the reservoir. Typical reserve recovery rates range from 40% to 50% of the original oil in place.

Waterflood:

- Is applicable on a reservoir-wide basis via dedicated injection wells.
- Can be integrated with other secondary or enhanced oil recovery methods.
- Requires uniform or well known reservoir permeability.
- Requires treatment of produced water and/or seawater.
- Can damage injection wells if water quality is poor.
- May require large turbine driven or multi-stage pump systems.
- Requires an ocean discharge from water treatment processes.

All of these secondary recovery methods have been used in the North Slope oil reservoirs and remain as options under the specific reservoir conditions identified above. Environmental issues differ little between these methods. Differences are primarily related to the specific ancillary facilities required (water supply, gas pipelines, etc.) and STP discharges.

**Enhanced (Tertiary) Recovery:** Enhanced or tertiary recovery options can be employed on reservoirs once secondary recovery options are no longer effective. Enhanced oil recovery methods include chemical flooding, miscible flooding, and thermal techniques. Chemical flooding methods (e.g., polymer, surfactant, and alkaline flooding) are characterized by the addition of chemicals to improve the flow of oil through the reservoir. Miscible flooding uses carbon dioxide, nitrogen, or hydrocarbons as a solvent, and thermal processes add heat to the reservoir to improve oil flow. Enhanced recovery methods are not considered until development/production from secondary recovery methods decline dramatically, typically many years into the production life of the reservoir. Only miscible flooding with hydrocarbons as enhanced recovery has been used on the North Slope.

#### *3.4.2.6 Oil and Gas Processing*

Produced reservoir fluids (a mixture of oil, water, and gas) are processed by separating crude oil, produced water, and gas. The processing facilities for an offshore reservoir may be located entirely offshore, entirely onshore, or with parts in either location. Processing requirements depend upon reservoir characteristics, production rates, and the types of secondary oil recovery methods. These requirements also may differ depending upon a reservoir's distance to shore and its proximity to existing oil and gas processing facilities. Offshore oil and gas processing options can be used with one or more secondary recovery methods.

Considerations for determining an appropriate oil and gas processing option include:

- Distance of the development/production structure to existing processing facilities.
- Method for transporting oil and/or gas (tankers or pipelines).
- Size of development/production structure required to support the processing facilities.

Fluids produced at the wellhead contain oil, gas, and water and are called "three-phase fluids." Partial processing removes much of the gas and some of the water from the oil, leaving a three-phase mixture that still contains small amounts of gas, some water, and oil. Pipelines can be used to transport unprocessed, partially-processed, or fully-processed crude oil. Pipelines carrying three-phase fluids are not technically feasible for distances greater than about 12 miles (19.3 km) because inconsistent mixtures at the wellhead make pumping difficult over long distances. Non-pressurized tankers and barges are unable to transport three-phase fluids. Fully processing reservoir fluids to remove water and separate the oil and gas results in a uniform, consistent crude oil product which can be transported by a variety of vessel types, and a uniform consistent gas product which can be reused on site for secondary recovery or transported by pipeline for use or sale at another location.

The size and location of the reservoir, as well as the reservoir characteristics, are important factors for determining processing facility needs. Because of the cost of processing equipment, a small reservoir alone may not support an independent processing facility; however, in combination with others, it may be economical to develop small reservoirs. Offshore reservoirs within the 12-mile (19.3 km) range of a three-phase fluid pipeline could be developed by connecting to existing processing facilities (onshore or offshore) with excess capacity for handling produced fluids. If excess capacity is not available, the distance is too long, or transport of mixed-phase fluids is to be avoided, partial or full processing can be done at a new offshore site. Processing on site allows for reuse of products in secondary recovery which may not be possible if processing is completed at a different site. Since the equipment types and size are similar for partial and full processing, the impacts of these options are expected to be about the same. These impacts include the footprint of the structure used for processing, noise of equipment in operation, noise from transportation of supplies and people, discharges of wastes, and accidental release of hydrocarbons or other toxic materials. Impacts can be reduced if no processing occurs at the reservoir site; however, the impacts would occur at the alternative processing site and may have similar or greater effects there. If processing cannot be done at the reservoir site, such as when a permanent structure cannot be maintained, the offsite option would be the only one available.

Site-specific concerns about processing impacts may influence selection of a processing site, but the more likely factors are economics of the reservoir and transportation of the products. In water depths less than about 100 ft (30.5 m) in the Alaskan Beaufort Sea, where a stable structure can be placed and protected from ice forces, full processing at the offshore reservoir site is expected to be proposed because it avoids three-phase and two-phase fluid transportation problems. In deeper water, other alternatives may be considered; however, since none have been seriously considered, it is difficult to predict what technology may be developed and proposed in the future.

### *3.4.2.7 Transportation of Product*

Transportation of oil and gas products from the Alaskan Beaufort Sea to world markets could be accomplished by a variety of methods, such as vessels, pipelines, railroad, or trucks. It is expected that the existing TAPS pipeline and Dalton Highway would be used rather than developing duplicate facilities for the onshore portion of transportation. For the offshore area, there are no existing pipelines, ports, fuel storage, or shipping facilities. Thus new systems would be required for offshore development. Listed below are transportation options and a summary of their associated limitations.

Offshore transportation:

- Tankers to market – petroleum product must be processed to crude oil, icebreaker support required, seasonal shipping.

- Barges to coastline – same as tankers; in addition, shoreline transfer and onshore transportation facilities required.

- Pipeline to shoreline – three-phase, gas, or crude oil transport possible; new pipeline required as none exist in Alaskan Beaufort Sea; year-round operation.

Onshore transportation:

- Railroad – product must be processed to crude oil, new railroad system required as none exist north of Fairbanks, year-round operation.

- Trucks – product must be processed to crude oil, year-round operation on existing roads.

- Pipeline – three-phase, gas or crude oil transport possible; use of new or existing pipelines, including existing common carrier pipelines and the TAPS; year-round operation.

Railroad and truck transportation of crude oil is unlikely to occur because of the existence of the TAPS and a perceived need to find additional oil to keep the TAPS in operation as Prudhoe Bay production declines. Rail and truck transportation also have higher spill risk than pipelines because of increased transfers between vessels and tanks. For these reasons, use of either railroad or truck transport of crude oil from the North Slope is considered unlikely. Use of tankers, barges, and pipelines are discussed below.

**Tankers:** If an offshore production facility can provide full processing of the crude oil, tankers could carry the oil directly to world markets. Such a system would require a mooring and loading system (possibly with vapor recovery), and a large capacity crude oil storage site to hold products between tanker callings. Small and super tankers require a minimum of 60 ft (18.3 m) and at least 120 ft (36.6 m) of water depth, respectively. Therefore, a channel for tanker access must be dredged in shallower waters. Alternatively, a pipeline from the development/production facility to a tanker loading site located in deeper water could be constructed. Ice management would be required to keep tankers operating for much of the year. In some areas, ice conditions would prohibit safe transportation by tankers. Tankers also present an increased risk for oil spills to occur during tanker loading/unloading activities.

The use of tankers to transport crude oil from the Alaskan Beaufort Sea was attempted in 1969. However, it was determined that tankering crude oil from the Alaskan Beaufort Sea could not compete economically with an onshore pipeline system from the North Slope. Offshore reservoir development proposals may reopen the question of tankering from the Alaskan Beaufort Sea. Under certain circumstances, this may be a feasible or preferred option for transportation of products.

**Barges:** If an offshore production facility can provide full processing of the crude oil, barges could be used to transport crude oil between an offshore site and the shoreline without the dredging requirement of tankers. A dock, such as existing facilities at Oliktok Point, West Dock, East Dock, and Badami may be used to reach the required water depth of 6 to 8 ft (1.8 to 2.4 m) for barge operation. Occasional or frequent dredging may be required to maintain these depths at the shoreline unloading site, depending on sediment transport at the site (Section 5.3). Barges usually can operate between late-July and mid-September in the Alaskan Beaufort Sea; however, icebreaker support would be required to extend the shipping season into winter months. Barge transport of crude oil to the Alaskan Beaufort Sea coastline would also require construction of a loading/unloading facility connected by pipeline to the TAPS. Barges also present an increased risk for oil spills to occur during barge loading/unloading activities.

Under certain conditions, barging crude oil to the shoreline for transport through the TAPS may be feasible. When a pipeline cannot be constructed, barging may be the only remaining option; however, this is likely to result in only seasonal production from the offshore site.

**Pipelines:** Pipelines could transport three-phase fluids or crude oil to the Alaskan Beaufort Sea coastline and on to existing oil and gas facilities or to the TAPS. Pipeline installation from offshore development/production structures to the Alaskan Beaufort Sea coastline may occur on gravel-filled causeways, elevated pile-supported structures, the seafloor, or buried or drilled beneath the seafloor. A combination of these methods may be used to cross different types of seafloor conditions.

Once pipelines reach the coastline, onshore pipelines constructed on elevated VSMs or other types of pipelines would continue to carry the fluids to their destination. Depending on the landfall site, pipelines may join existing routes, tie-in to a common carrier pipeline, or be the first pipeline in the area.

<u>Onshore Pipeline Corridor</u>: Onshore pipelines installed on elevated VSMs are currently the conventional method of oil and gas transportation on the North Slope. Selection of an onshore pipeline route would consider environmental issues, project cost, and access to the pipeline. These factors may include:

- Maximizing the use of existing disturbed area, such as pipeline corridors and roadways.
- Avoiding high value fish and wildlife habitat.
- Minimizing total pipeline length and expense.
- Avoiding conflicting land uses such as native allotment, federal reserve lands, and cultural/ archaeological sites.

In some cases, reasonable alternatives may not satisfy all the considerations identified above. A range of alternative routes would be considered to allow comparison of alternatives which satisfy concerns in different ways.

<u>Gravel-filled Causeway</u>: A gravel causeway is a manmade structure that connects an offshore development/ production facility to the mainland. It is constructed by placing gravel onto the seafloor until it extends above water. Pipelines are installed on top of, or within, the causeway. The causeway protects the pipeline from waves and ice, and provides access for maintenance and repairs. Gravel-filled causeways can be continuous or broken by openings called “breaches” that allow small vessels, coastal water, and marine organisms to pass beneath bridged pipeline sections.

Causeway construction is most practical when the offshore facility is located in shallow water and relatively close to shore (e.g., the Endicott development). Existing causeways in the Alaskan Beaufort Sea are 3 to 5 miles (5 to 8 km) in length and extend to water depths of 12 to 14 ft (3.7 to 4.3 m). Impacts of causeways on coastal circulation and fish movements preclude their use along some portions of the coastline. The presence of a relatively continuous band of low salinity water along the coastline during July and August (Section 5.5) is critical for feeding and distribution of some anadromous fish species (Section 6.4). The low salinity water is created by river runoff and summer wind patterns. Causeways constructed perpendicular to the shoreline disrupt the coastal band of water and may induce local upwelling of high salinity water near the shoreline. Either the physical presence of the causeway or the break in the low salinity corridor, can delay or stop movement of some fish, particularly broad whitefish and young-of-the-year Arctic cisco, which are two important subsistence fish species (Section 7.3). A causeway proposed for an area where water and fish movements are a concern would be unacceptable unless it has adequate breaching, particularly near the coastline to allow water and fish movement. This concern would be evaluated on a site specific basis.

Elevated Pile-Supported Structure: A pile-supported pipeline would extend above sea level to allow water and fish to pass unimpeded; however, this could present an impediment to navigation. Since a pile-supported structure in the Alaskan Beaufort Sea would be exposed to winds, wave action, and ice forces, it is most suited for offshore development/production facilities close to the shore. Even in the bottomfast ice zone (water depths less than 6 ft [1.8 m]), the pipeline would be at risk of damage from moving ice during breakup and freezeup. Since current directional drilling technology has a horizontal "reach" of approximately 4 miles (6.4 km) (Section 3.4.2.3), elevated, pile-supported causeways would not be practical for accessing reservoirs that are less than 4 miles (6.4 km) from shore because they can be reached from an onshore drilling location. Due to the costs of building pile-supported structures and the limited distance they could be used offshore, this option is not considered reasonable for use in the Alaskan Beaufort Sea.

Installed on the Seafloor: Pipelines from offshore oil and gas development/production facilities to onshore facilities are laid directly onto the seafloor in many regions of the world. In the Alaskan Beaufort Sea, bottom-fast ice, ice gouging, and strudel scour occur from the coastline out to depths of about 200 ft (61 m) (Section 5.6). Ice and sediment movements would likely rupture or damage pipelines installed on the seafloor. In water deeper than 200 ft (61 m) pipelines could be laid on the seafloor. Facility options and the means of drilling in greater than 200 ft (61 m) of water are fairly limited.

Buried Beneath the Seafloor: The only other arctic subsea buried pipeline connecting offshore and onshore facilities was constructed at the Drake gas field in the Canadian Beaufort Sea in 1978. The following paragraphs present a brief discussion of this buried subsea pipeline, as presented in Brown (1996:1-9), Palmer et al. (1979:765-772), and Watts and Masterson (1979:755-764).

The pipeline extended into the McClure Strait in Canada, located off the Sabine Peninsula of Melville Island in the Northwest Territories, approximately 800 miles (1,287 km) east of the Alaska/Canada border. The pipeline was built by Panarctic Oils Ltd. to test technologies that could potentially be useful in the development of hydrocarbons in high arctic regions. This specifically included the ability to work off the ice sheet, as well as several other aspects related to pipeline installation and performance.

The pipeline was approximately 3,050 ft (929.6 m) in length and extended from the shoreline to the wellhead, located in 181 ft (55 m) of water. The 820 ft (250 m) nearshore portion of the subsea pipeline was trenched approximately 5 ft (1.5 m) beneath the seafloor using a plowing technique. This was deemed necessary to avoid potentially damaging effects from floating multi-year ice that was assumed to have seafloor effects down to water depths of approximately 65 ft (19.8 m), primarily during periods of breakup. The portion of pipeline in water depths greater than 65 ft (19.8 m) was installed on the seafloor.

The pipeline was tested by allowing a limited quantity of gas to flow from the well, but the well was never placed into operational service. The pipeline was intended to become part of a larger hydrocarbon transportation scheme, but related transportation facilities needed for long-term operation of the well and pipeline were never built. The project was undertaken at a time when crude oil prices were $50 per barrel and hydrocarbon prices were projected to continue to increase. However, hydrocarbon prices began a decline shortly after the pipeline was installed that has continued to this day. The costs to transport hydrocarbons from the area exceeded the economic return at these lower prices.

Since the pipeline was not placed into service, there was no program of monitoring, research, or maintenance. The pipeline was officially abandoned in 1996-97, approximately 18 years after it was constructed. As part of abandonment, a limited survey of the condition of the pipeline was undertaken which showed no apparent damage. The well remains plugged and abandoned.

Pipelines buried beneath the seafloor in the Alaskan Beaufort Sea could avoid damaging effects from ice in waters less than 200 ft (61 m) deep. To accomplish this, pipeline burial depths would have to be determined based on anticipated depths of ice gouge and related stresses and strudel scour events. Methods for installing pipelines beneath the seafloor by trenching include:

· Plowing - a device similar to a farmer's plow is pulled along the seafloor by a vessel (effective in water depths up to 200 ft [61 m]).

· Jet sledding - high pressure water jets are towed along the seafloor by a vessel (effective in all water depths).

· Trenching - Conventional or modified hydraulic excavators and mechanical pipeline trenching machines may be used through the ice in water depths dependent on specific equipment limitations.

Selection of a buried pipeline trench excavation method in the Alaskan Beaufort Sea would depend upon water depth, time of year, length of pipeline, seafloor sediments, equipment availability, and pipeline depth.

When a pipeline cannot be buried deeply enough, another option would be to directionally drill and then pull pipe through the tunnel created. Directionally drilled pipelines have been installed beneath large rivers and barrier islands. A small diameter pilot hole is drilled, and a reamer attached and pulled back through the hole to increase the diameter. A single pipe or several pipes bundled together can be pulled through the hole. This method is limited to distances of approximately 1.25 miles (2 km) due to the weight of the drillstring and the pipeline. Its use may also be limited by the substrate. Loose, unconsolidated soils are difficult to drill through because they tend to collapse. The drilling depth may be adjusted, or special techniques used, to avoid problem areas.

<u>Offshore Buried Pipelines: Single- versus Double-walled</u>: A description of the single-walled pipeline is described in detail in Appendix A and in the Technical Notes, Appendix E. In this EIS, a double-walled pipe is defined as an oil carrier pipe inside of an external pipe. This configuration may be designated as pipe-in-pipe, cased pipe, or pull tube depending on the actual pipeline design. Conceptually, a double-walled pipe design could be used at locations susceptible to adverse environmental conditions. In

conceptual design and in limited field applications (testing, but not operational) such a pipeline design could increase pipeline integrity, provide oil spill containment, and enhance leak detection. The determination of the actual benefits versus costs and risks associated with single and double-walled pipeline alternatives require a project specific analysis based on the most current available knowledge.

Pipe-in-pipe designs are currently used offshore for some insulated pipelines and to bundle multiple smaller pipelines together. In the Gulf of Mexico, it is used in some deep-water applications to physically protect pipeline insulation from damage during construction and operations. Building multiple pipes in a single, larger pipeline keeps the pipelines together and simplifies the installation process. In the Northstar application, pipe insulation is unnecessary to retain heat and prevent hydrate or wax formation inside the pipeline nor is it necessary to ease installation.

Although double-walled pipes have not historically been used on the North Slope for transportation of oil and gas, two developments have incorporated features of a doublewall configuration into their pipeline designs. First, BPXA has proposed installation of a pull tube for the Liberty development during construction of the island. This would allow subsequent installation of the pipeline bundle the following year without excavation of part of the island. Second, ARCO's Alpine development will use a cased pipeline configuration for the Colville River crossing. ARCO's 4,300-foot cased pipeline underground crossing of the Colville River was designed to minimize the possibilities of a pipeline leak, provide secondary containment, provide redundant structural integrity, and to accommodate portions of the external loads that would normally be carried by the carrier pipe (ARCO, 1997:2-14, 2-19, 2-20).

The Alpine Colville River crossing "pipeline-within-a-pipeline" for the above cited functions combined with horizontal directional drilling approach remains unique in pipeline river crossings within the North Slope of Alaska. In construction of the Colville River crossing, operations begin by drilling a small pilot hole. Once the pilot hole is completed, it is enlarged by making multiple passes with a reamer. The carrier and casing pipe strings are then fabricated, welded, non-destructively examined with radiographic and/or ultrasonic techniques, hydrotested (carrier pipe only), and the pipe joints coated. The carrier pipe is then installed within the casing and the combined assembles are then pulled through the enlarged hole. Simultaneous failure of both the carrier oil pipeline (0.438-inch wall thickness) and the casing pipeline (0-5-inch wall thickness) is unlikely. If oil leaked from the carrier pipeline, it would be captured within the spaces between the outer wall of the carrier pipeline and the inner wall of the high-strength casing pipe, rather than reaching the subsurface river environment. This design is analogous to secondary containment provided as a spill prevention technique for storage tanks. The casing performs a second function in that it is designed to accommodate portions of the external loads that would normally be carried by the carrier pipe (ARCO, 1997:2-28). One load exerted on the casing and not on the inner carrier pipeline is the external pressure due to the surrounding soil. In addition, the casing will initially absorb bending due to thaw settlement because the carrier pipelines will be supported within the casings by loose fitting casing isolators. Since the carrier pipeline is smaller than that of the casing, its bending resistance will be much smaller than that of the casing. And, since the carrier pipeline will not be rigidly attached to the casing and there will be gaps between the isolators and casings, it is possible for the casing to bend without bending the carrier pipeline. Thus the curvature of the carrier pipeline will always be less than the curvature in the casing at the same location. However, once the carrier pipeline has started to bend, the bending resistance of the composite (casing and carrier pipelines) is essentially the sum of the two bending resistances (Baker, 1998).

To prevent external corrosion, all the casing pipes and carrier pipes are protected by a mechanically tough state-of-the-art fusion-bonded epoxy coating. In addition, an 8-inch pipe parallel to and near the casing pipes provides the anode portion of an impressed cathodic protection system to address corrosion of the casing pipes. ARCO has included various spill detection techniques to provide early warning of potential problems (ARCO, 1997:2-28). One is a Pressure Point Analysis (PPA) system, a computerized leak detection system. The PPA system depends upon sampling frequency and the speed of sound in the liquid to compare instantaneous pressure data to trended pressure data using a computer algorithm to determine if there is evidence of a leak. The current trend data are also compared with data sets that characterize leak profiles. The PPA system is also supplemented with the traditional mass balance leak detection system used in current advanced pipelines. Although the mass balance detection system is effective, it is also limited in detecting small quantity leaks based on the accuracy of the flow meters. ARCO will also install an independent hydrocarbon sensor to monitor below current threshold leak detection limits in the space between the cased pipeline and carrier pipeline. The sensor system is a fiber optic based system capable of distinguishing between hydrocarbons, salt water, and fresh water (Fowler - Pers. Comm., 1999:1).

The extent of applicability or feasibility of transferring a 4,300-foot doubled-walled pipeline river crossing technique to multi-mile subsea Arctic oil pipeline requires detailed information and analysis which is currently not available. There remains a degree of uncertainty that could affect structural integrity and pipeline safety. The practicability, applicability, and current technological limitations or constraints associated with the use of a multi-mile double-walled pipeline in a subsea Arctic environment are currently unknown.

Some influencing or constraining factors are expected in the construction, installation, and operation of a multi-mile doubled-walled pipeline configuration compared to a single pipeline configuration. The use of horizontal directional drilling technology, as used in Alpine, is not considered as a practicable installation technique for the subsea pipeline. Subsea installation difficulties could result from increased pipeline buoyancy associated with annular spaces between the external and carrier pipes. Depending on the design and operational conditions, the resultant buoyancy of the pipelines could cause the assembly to shift or even migrate (float) upwards. Other installation difficulties associated with a double-walled pipe compared to a single-walled pipe configuration could include: summer time construction requirements; increased weight and stiffness of the pipeline; need for heavier pipe handling equipment; and additional time requirements for fabrication (primarily welding), quality control, and installation of the pipeline. Double-walled pipes could be at a higher risk from some types of pipeline failure, such as trauma from ice gouging that was not a factor for the Alpine cased pipeline feasibility determination. It is also possible that external trauma causing failure to the exterior pipe could also breach the inner carrier pipe defeating the secondary containment function of the double-walled pipeline. On the other hand, if a small leak occurs in the carrier pipeline, it could be contained in the double-wall pipeline configuration with the potential of providing an increased detection and containment before reaching the environment. The same can not be said for a single-walled pipeline design. Repair of a damaged doubled-walled pipeline would be more difficult than repairing a single-walled pipeline.

Offshore Buried Pipelines, Landfall Location Alternatives: The point where an offshore buried pipeline intersects the coastline and begins an onshore transition is called a pipeline landfall location. Pipeline landfall locations may require onshore gravel pads to accommodate pipeline valves and leak detection equipment. Equipment at these landfall locations would also require vehicular access by gravel road, or a helipad to accommodate access by helicopter. Environmental and engineering concerns which may be considered when identifying potential pipeline landfall locations include:

- Avoid large river delta systems to reduce strudel scour hazard.
- Avoid coastal areas with near-surface permafrost to minimize thaw subsidence.
- Avoid rapidly eroding shorelines to reduce the need for pipeline protective structures.
- Avoid high value fish and wildlife habitats.
- Avoid cultural or archaeological sites.
- Avoid areas where historical subsistence use is high.
- Allow access/connection to existing onshore oil and gas facilities.
- Minimize offshore and overland route lengths.

In some cases, reasonable alternatives may not satisfy all the considerations identified above. A range of alternative landfall locations should be considered to allow comparison of alternatives which satisfy concerns in different ways.

Offshore Buried Pipelines, Corridor Alignments: The determination of offshore pipeline alignments connecting an offshore oil and gas development/production facility with a pipeline landfall location may consider environmental issues, construction cost, construction feasibility, and obvious hazards, such as:

- Limit offshore pipeline length in water depths greater than 20 ft (6.1 m) because it requires special excavation equipment or open water dredging.

- Limit offshore pipeline length in water depths greater than 6 ft (1.8 m) because working on floating ice is slower and more difficult than working on bottomfast ice.

- Minimize pipeline fabricated bends to reduce construction costs and improve reliability.

- Avoid proximity to river deltas to minimize potential impacts from strudel scour events.

- Avoid high value fish and wildlife habitat, such as the Boulder Patch.

- Avoid areas of near surface subsea permafrost to minimize thaw subsidence.

In some cases, reasonable alternatives may not satisfy all the considerations identified above. A range of alternative routes should be considered to allow comparison of alternatives which satisfy concerns in different ways.

### *3.4.2.8 Development/Production Facilities Abandonment/Reuse Potential*

When production from a reservoir ceases, oil and gas facilities would be abandoned in accordance with terms of individual lease agreements. Abandonment could range from complete removal of all facilities including pipelines, VSMs, and the production structure, to a shut down mode with most facilities left intact for future use. Requirements are decided at the time when the field is abandoned because of the unknown possibilities for future uses. For example, the lease agreements for the Northstar Unit state: "At the option of the state, all improvements such as roads, pads, and wells must either be abandoned and the sites rehabilitated by the lessee to the satisfaction of the state, or be left intact and the lessee absolved of all further responsibility as to their maintenance, repair, and eventual abandonment and rehabilitation." Possible uses of an island structure include other oil and gas projects, a deepwater port facility, scientific research projects, or a shelter for travelers ranging from subsistence hunters to tourists. A mobile production structure could be relocated for use at another reservoir. Pipelines are likely to be reused only if oil and gas production continues, or possibly to supply fuel for activities or housing. Housing facilities on an island may be of interest to local government, businesses, or individuals.

If no future uses for the facilities can be identified, structures may be removed. Removal is likely to involve similar activities to construction. Mobile production structures would be the easiest to remove, with gravel islands and pipelines the most difficult. Some facilities, (e.g., buried or drilled pipelines) could be abandoned in place, provided that safety and environmental regulations are met.

## 3.5 SUMMARY OF REASONABLE DEVELOPMENT OPTIONS AND PROCESS FOR THE DETERMINATION OF PROJECT ALTERNATIVES

As indicated in Section 3.4, the determination of appropriate alternatives for development of offshore oil and gas resources requires consideration of a variety of environmental factors and technical options. The preceding discussion identified several technical options which should be eliminated from further consideration due to environmental conditions in the Alaskan Beaufort Sea (Table 3-4). Options which merit further consideration are summarized in Table 3-5. Refining this list of options to identify reasonable alternatives for a specific development proposal requires consideration of general criteria, such as those listed for pipeline route selection, site-specific conditions, and technical factors. Economic factors and compatibility with the existing industrial support infrastructure are also important.

The location of the oil and gas reservoir and technical limitations to drilling are the primary factors defining the geographic area suitable for location of drilling facilities. As indicated in Section 3.4.2.3, current directional drilling technology requires a drillsite to be within approximately 4 miles (6.4 km) of the desired bottom-hole location. In some cases, the characteristics of the oil and gas reservoir may limit the reach of directional drilling to lesser distances, although future advances in drilling technology also could extend the reach. For this reason, this factor should be evaluated specifically for each oil and gas development proposal. Once a geographic area of potential drilling locations is determined, environmental conditions and existing facilities within this area should be considered to select offshore production structure(s) suitable for the development proposed. Related activities, such as oil and gas processing and transportation methods, can then be evaluated in relation to the existing industrial infrastructure.

Figure 3-6 illustrates a simple process that incorporates the information presented in Section 3.4 into the selection of offshore production facility alternatives for a specific development proposal. The process shown is focused on selecting alternatives which are suitable to develop the resource, and are compatible with the environmental conditions of the site. This process presumes that development from an onshore site or an existing offshore structure is generally preferable to installation of new offshore structures. By answering the questions on Figure 3-6, a short-list of reasonable alternatives can be developed. This process is intended to illustrate the reasoning used for selection of alternatives to be evaluated in this EIS. The process eliminates alternatives which are clearly unsuitable or would involve substantially greater environmental impact and/or expense. However, specific project proposals that would not otherwise be identified using this process could still be evaluated in response to an applicant's request.

Table 3-4 (page 1 of 1)

Figure 3-6 (page 1 of 2)

Figure 3-6 (page 2 of 2)

Table 3-5 (page 1 of 3)

Table 3-5 (page 2 of 3)

Table 3-5 (page 3 of 3)

Once the locations and types of offshore structures have been selected, alternatives for other components and facilities can be developed. This requires consideration of options for each major project component, including: oil and gas recovery techniques, onshore or offshore gas processing, oil transportation methods, offshore pipeline routes (if applicable), pipeline landfall locations, and onshore pipeline routes. To avoid unnecessary evaluation of an unreasonably long list of alternatives with only subtle differences, environmental information collected early in the NEPA process should be applied to determine appropriate development/production options as described in Section 3.4. This process will lead to identification of alternatives which are distinctly different from one another.

Each of these alternatives may then be considered as representative of a particular “type” of alternative. For example, alternatives involving pipeline landfall locations on a natural shoreline and an existing manmade causeway allow comparison of these options without addressing all possible landfalls of each type. The use of the information in Section 3.4 also allows the consideration of technical and economic factors to avoid the evaluation of unreasonable alternatives.

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## TABLE 3-1
## PAST AND PROPOSED ALASKAN BEAUFORT SEA FEDERAL AND STATE LEASE SALES SUMMARY

| Lease Sale Number | Sale Date | Acres Offered |
|---|---|---|
| **Federal** | | |
| Sale #71 | October 13, 1982 | 1,825,770 |
| Sale #87 | August 22, 1984 | 7,773,447 |
| Sale #97 | March 16, 1988 | 18,227,806 |
| Sale #124 | June 26, 1991 | 18,556,976 |
| Sale #144 | September 18, 1996 | 2,947,247 |
| Sale #170 | August 5, 1998 | 1,900,000 |
| Future Sale: Sale #176 | 2000 | 12,200,000 |
| **State** | | |
| Sale #30 | December 12, 1979 | 341,140 |
| Sale #36 | May 26, 1982 | 56,682 |
| Sale #43 | May 22, 1984 | 298,074 |
| Sale #48A | February 25, 1986 | 42,053 |
| Sale #50 | June 30, 1987 | 118,147 |
| Sale #55 | September 28, 1988 | 201,707 |
| Sale #52 | January 24, 1989 | 175,981 |
| Sale #65 | June 4, 1991 | 491,091 |
| Sale #68 | June 2, 1992 (no bids placed) | 153,445 |
| Sale #86A | October 1, 1996 | 15,484 |
| Sale #86 | November 18, 1997 | 365,398 |
| Sale #87 | June 24, 1998 | Areawide |
| Future Sales: Beaufort Sea Areawide 1999 | October 1999 | 2,000,000 |
| **Joint Federal and State Sale** | | |
| BF | December 11, 1979 | 173,423 |

Sources: ADNR, 1995:76-77
USDOI, MMS, 1996:I-5

## TABLE 3-2
## SUMMARY OF CURRENT ONSHORE OIL AND GAS FACILITIES [1]

| Facilities | Alpine | Kuparuk | Tarn | West Sak | Milne Point[5] | Prudhoe Bay WOA/EOA | Point McIntyre | Lisburne | Niakuk | Endicott | Badami[2] |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Operator | ARCO | ARCO | ARCO | ARCO | BPXA | BPXA/ARCO | ARCO | ARCO | BPXA | BPXA | BPXA |
| Well Pads/Drill Sites | 2 | 43 | 2 | -- | 12 | 38 | 2 | 6 | 1 | 2 | 1 |
| Wells: Oil/Producers | 46 | 462 | 16 | 25 | 140 | 1,079 | 48 | 78 | 12 | 74 | 1 |
| Gas Injectors | 2 | 300[3] | 6 | -- | -- | 36 | 1 | 4 | 0 | 5 | 0 |
| Water Injectors | 44 | 162 | -- | 25 | 63 | 182 | 14 | 0 | 4 | 28 | -- |
| Central Compression Plant | 1 | -- | -- | -- | -- | 1 | -- | -- | -- | -- | -- |
| Central Gas Facility | 1 | 1 | -- | -- | -- | 1 | -- | -- | -- | -- | -- |
| Central Oil/Gas Separation Plant | 1 | 3 | -- | -- | 1 | 6 | -- | 1 | -- | 1 | 1 |
| Central Power Station | 1 | 1 | -- | -- | -- | 1 | -- | -- | -- | -- | -- |
| Crude Oil Topping Unit | -- | 1 | -- | -- | -- | 1 | -- | -- | -- | -- | -- |
| Personnel Living Quarters | 1 | 3 | -- | -- | 1 | 5 | -- | -- | -- | 1 | 1 |
| Seawater Injection Plant | -- | 1 | -- | -- | -- | -- | -- | -- | -- | 1 | -- |
| Seawater Treatment Plant | -- | -- | -- | -- | -- | 1 | -- | -- | -- | 1 | -- |
| Airstrip | 1 | 1 | -- | -- | -- | 1 | -- | -- | -- | -- | 1 |
| Helipad | -- | -- | -- | -- | -- | 2 | -- | -- | -- | -- | -- |
| Dock | -- | 1 | -- | -- | -- | 2 | -- | -- | -- | 1 | 1 |
| Gravel Mine Site/Water Reservoir | 1[4] | 4 | 1 | -- | 1 | 2 | -- | -- | -- | 1 | 1 |
| Gathering Pipeline (miles) | 3 | 97 | -- | -- | 30 | 145 | 12 | 50 | 5 | 3 | -- |
| Common Carrier Pipeline (miles) | 40 | 37 | 10 | -- | 10 | -- | -- | -- | -- | 26 | 27 |
| Roads (miles) | 3 | 19 | | -- | 10 | 110 | 3 | 10 | 1 | 10 | 4.5 |

Notes:
1 = As of December 31, 1997
2 = Includes both oil and gas pipelines in a common corridor
3 = Alternating gas and water injection
4 = Lake with fish only
5 = Includes Cascade

ARCO = Arco Alaska, Inc.
BPXA = BP Exploration (Alaska) Inc.
EOA = Eastern Operating Area
WOA = Western Operating Area
-- = Not applicable

Source: Hanley, 1997:Attachment 6; USDOI, BLM, 1998:Table IV, A.5-5; Thomas et al., 1993:xiii

## TABLE 3-3
## DESIGN AND OPERATING CAPACITY FOR NORTH SLOPE ONSHORE OIL AND GAS FACILITIES

| Reservoir [1] | Design | | | Operating | | | Comments |
|---|---|---|---|---|---|---|---|
| | Oil (MBPD) | Gas (MMSCFD) | Water (MBPD) | Oil (MBPD) | Gas (MMSCFD) | Water (MBPD) | |
| Badami | 35 | 22 | 31 | NA | NA | NA | |
| Prudhoe Bay Unit | | | | | | | |
| GC1 | 350 | 2,500 | 190 | 160 | 2,500 | 105 | Facilities are gas limited. |
| GC2 | 350 | 1,100 | 320 | 110 | 1,100 | 280 | |
| GC3 | 320 | 1,100 | 250 | 70 | 1,100 | 150 | |
| FS1 | 350 | 2,700 | 120 | 140 | 2,700 | 129 | |
| FS2 | 350 | 1,300 | 700 | 90 | 1,350 | 700 | |
| FS3 | 350 | 1,350 | 240 | 82 | 1,350 | 116 | |
| CCP/CGF | NA | 7,600 | NA | NA | 7,600 | NA | Miscible Injection Expansion (MIX) will increase capacity to 8,200 MMSCFD. |
| West Dock STP | NA | NA | 2,300 | NA | NA | 300 | Point McIntyre is the only user. |
| Endicott | 120 | 480 | 200 | 60 | 480 | 180 | Facility is gas limited. |
| Kuparuk | 340 | 540 | 800 | 270 | 540 | 790 | Excludes Alpine Projections. |
| Milne Point | 75 | 42 | 40 | 57 | 38 | 38 | |
| Lisburne | 220 | 450 | 180 | 188 | 340 | 96 [2] | |
| Point McIntyre | NA | NA | NA | NA | NA | NA | Runs through Lisburne Production Center |
| Niakuk | NA | NA | NA | NA | NA | NA | Runs through Lisburne Production Center |

Notes:
- 1 = Location of facilities shown on Figures 3-2a through 3-2c.
- 2 = Limited by ability of injection wells to accept injected fluids.
- CCP = Central Compressor Plant
- CGF = Central Gas Facility
- FS = Flow Station
- GC = Gathering Center
- MBPD = Thousand barrels per day
- MMSCFD = Million standard cubic feet per day
- NA = Not applicable
- STP = Seawater Treatment Plant

Source: Campbell - Pers. Comm., 1998:1

**TABLE 3-4**
**OPTIONS ELIMINATED FROM FURTHER EVALUATION**
**FOR DEVELOPMENT/PRODUCTION IN THE ALASKAN BEAUFORT SEA**

| Development/Production Components | Options | Reason for Elimination |
|---|---|---|
| Oil and Gas Drilling Methods (Section 3.4.2.3) | Vertical Drilling Technology | XOnly accesses portions of a reservoir directly beneath the surface drilling location.<br>XMultiple drilling structures at multiple drilling locations increases overall development/production costs and creates an increase in potential environmental concerns. |
| Offshore Production Structures (Section 3.4.2.4) | XFloating Structures<br>- Jackup Drilling Platforms | XNot designed to operate in an ice environment or to support long-term development/production activities. |
| | - Semi-Submersible Drilling Vessels | XNot designed to operate in an ice environment or to support long-term development/production activities. |
| | - Conventional Drillships | XNot designed to operate in an ice environment or to support long-term development/production activities. |
| | - Conical Drilling Unit (Kulluk) | XNot designed to operate in an ice environment or to support long-term development/production activities. |
| | - Ice Islands | XMelt in summer when ambient air temperatures are above freezing. |
| | XIsland Structures<br>- Caisson Retained Island (CRI) Designs and Tarsiut Island (Concrete CRI) | XRelocation expected to be very difficult because the caissons are ballasted with sand, rather than water.<br>X Redesign and construction of a new caisson structure would create a purpose-built structure and would be expected to be very costly compared to other options. |
| | XSubsea and Subterranean Structures<br>- Subsea Cavern | XUnproven concept not yet demonstrated as technically or economically feasible.<br>XSafety concerns related to gas build-up, fire/explosions, evacuation, blowouts, etc.<br>XWould create a large volume of excavated material that would require disposal.<br>XPermafrost stability concerns around the cavern and entrance to the cavern. |
| Oil and Gas Recovery (Section 3.4.2.5) | XEnhanced (Tertiary) Recovery | XNot considered in this Environmental Impact Statement because options are unknown. |
| Transportation of Product (Section 3.4.2.7) | XPipeline<br>Elevated Pile-supported Structure | XWould be exposed to winds, wave action, and ice forces and would be difficult to design for this exposure.<br>XStructure could impede passage of vessels/barges beneath or through it as a result of pile spacing and elevation above the sea surface. |

Notes: ft = Foot or feet m = Meter(s) % = Percent