CHAPTER 4.0

NORTHSTAR UNIT DEVELOPMENT/PRODUCTION ALTERNATIVES

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4.0 NORTHSTAR UNIT DEVELOPMENT/PRODUCTION ALTERNATIVES

4.1 INTRODUCTION

Chapter 4 of this Environmental Impact Statement (EIS) addresses National Environmental Policy Act requirements to identify reasonable alternatives, including the No Action Alternative, for further analysis. Reasonable alternatives are developed in Section 4.2 by applying the process discussed in Section 3.5. Section 4.3 identifies the alternatives considered but eliminated from detailed analysis in this EIS. Section 4.4 presents a detailed discussion of the alternatives selected for further evaluation in this EIS. The No Action Alternative is discussed first, and provides a basis for comparison of impacts associated with the action alternatives. BP Exploration (Alaska) Inc.'s (BPXA) proposed action is presented next, followed by the other action alternatives. Sections 4.5 and 4.6 discuss the agency preferred alternative and the environmentally preferred alternative, respectively.

Issues and Concerns: Chapter 4 addresses the following questions concerning alternatives for Northstar Unit development:

Issues/Concerns	Section
· What characteristics of the Northstar Unit and reservoir affect the determination of alternatives?	4.2
· What development/production location and structure type is reasonable for the Northstar Unit?	4.2
· What alternatives were identified, but eliminated from detailed analysis, and why were they eliminated?	4.3
· What are reasonable alternatives for development of the Northstar Unit?	4.4
· What is the environmentally preferable action alternative?	4.5
· What is the preferred action alternative?	4.6

4.2 DEVELOPMENT OF POTENTIAL ALTERNATIVES

4.2.1 Overview

The process for selecting reasonable alternatives to be considered for further evaluation in this EIS, and eliminating alternatives which are unsuitable or would involve substantially greater environmental impact and/or expense, was presented in Section 3.5. This process presumes that development/production from an onshore site or an existing offshore structure is generally preferable to the installation of new offshore structures because new structures would add to cumulative impacts. An exception to this general case would occur if the existing site or facility involved a special environmental or technical issue. The general approach and special considerations involved in selecting the development/production location and structure type are outlined on Figure 3-6, and are applied to the specific characteristics of the Northstar Unit in Section 4.2.2. Other components of development/production are reviewed through similar reasoning to select: oil and gas recovery techniques, oil and gas processing facility options, product transportation options, gravel source options, spoils disposal options (required due to consideration of buried pipelines), and construction schedule options (winter versus summer season). Each of these facility and support requirements are discussed in the following sections.

4.2.2 Determination of Drilling/Production Facility Alternatives

4.2.2.1 Northstar Unit Reservoir and Site Characteristics

The Northstar Unit is located between 2 and 8 miles (3 and 13 kilometers [km]) offshore of Point Storkersen in the Alaskan Beaufort Sea, and covers approximately 60 square miles (155 square km) (Figure 4-1). The northeastern portion of the unit lies in federal waters and consists of two federal oil and gas leases (Outer Continental Shelf Y-0179 and Y-0181). The remainder of the unit lies in state waters and consists of five state oil and gas leases (Alaska Division of Lands [ADL] 312798, ADL 312799, ADL 312808, ADL 312809, and ADL 355001). The portion of the Northstar Unit within state waters also lies within the jurisdiction of the North Slope Borough (NSB) coastal management program and land management regulations.

A portion of Long Island, one in a series of natural barrier islands paralleling the coastline 3 to 5 miles (5 to 8 km) offshore, is located in the southwest corner of the Northstar Unit. Two manmade gravel islands, Seal and Northstar Islands, were built within the Northstar Unit to support previous oil and gas exploration activities. Northstar Island, in the northwest corner of the unit in 43 feet (ft) (13.1 meters [m]) of water, has since eroded to below sea level and has become the Northstar Island shoal, while portions of Seal Island, centrally located in the unit in 39 ft (12 m) of water, remain above the sea surface. Water depths over the Northstar Unit range from 0 ft along the shoreline of Long Island to depths approaching 45 ft (13.7 m) near the Unit's northern boundary.

Bottomfast ice occurs over portions of the Northstar Unit where water depths are less than approximately 5 ft (1.5 m). The remaining portions of the Northstar Unit are within the relatively stable, floating landfast ice zone. The more dynamic stamukhi or shear ice zone, begins in approximately 65 ft (20 m) of water, occurring approximately 3 to 5 miles (5 to 8 km) further offshore than the Northstar Unit.

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Northstar Unit Exploration History: The two federal and four state leases were acquired by Amerada Hess Corporation, Amoco Production Company, Murphy Oil USA, Inc., Shell Western Exploration & Production Inc., and Texas Eastern Corporation as a result of successful bidding in the 1979 joint State/Federal BF Lease Sale. A fifth state lease (ADL 355001) was acquired by these companies in 1982 through State Lease Sale No. 36. These leases now comprise the Northstar Unit.

Six exploration wells were drilled within the Northstar Unit between 1983 and 1986 from two manmade gravel islands, Seal and Northstar Islands, constructed specifically for exploratory drilling activities (Figure 4-2). Seal Island, constructed in 1982, was used for drilling three wells which located hydrocarbons in the Ivishak formation, and a fourth well which was dry. Northstar Island, constructed in 1985, was used for drilling two wells; one confirmed the extension of hydrocarbons in the Ivishak formation, and the second was abandoned because of mechanical difficulties downhole. A seventh well, a dry hole, was drilled in 1994 from Long Island. Four of the seven exploratory wells were deemed capable of producing hydrocarbons in commercial quantities: Northstar No.1 drilled from Northstar Island; and Seal Island Nos. 1, 2, and 3 drilled from Seal Island. All seven exploration wells were plugged and abandoned in accordance with state and federal regulations.

In 1989, a Northstar Unit Agreement was entered into among the U.S. Minerals Management Service (MMS), Alaska Department of Natural Resources (ADNR), and the original leaseholders named above. A Unit Agreement is a mechanism through which multiple leases, contiguous to one another, are administratively combined and managed as a single lease under a single operator to promote more effective and efficient management of oil and gas reservoirs. The Northstar Unit Agreement defines how costs, liabilities, and benefits incurred in maintaining or conducting operations are apportioned and assumed among the owners. The Unit Agreement also discusses procedures for exploration, development, and production activities within the Unit.

The original leaseholders abandoned Seal and Northstar Islands in 1994 under plans approved by state and federal agencies. BPXA entered into discussions with the original leaseholders for acquisition of a working interest and operatorship of the Northstar Unit, and developed conceptual engineering designs for reservoir development. By the end of February 1995, agreements were reached for BPXA's purchase of the Northstar Unit. BPXA became 98 percent (%) owner of the Unit and Murphy Oil USA, Inc. retained 2% interest. The Unit Agreement was transferred to BPXA in 1995 and amended in 1996 to reflect changes in royalty payments.

Northstar Reservoir Characteristics: The Northstar reservoir is approximately 2 miles (3.2 km) wide and 8 miles (13 km) long, oriented in a northwest-southeast direction with the central axis of the reservoir generally located beneath Seal and Northstar Islands (Figure 4-2). Figures 4-3 and 4-4 represent cross-sections through the reservoir that show reservoir thickness beneath Seal and Northstar Islands. As depicted, these reservoir cross-sections suggest that the Seal Island location is over the center of the reservoir's thickest and most promising area in terms of potential oil recovery.

Results of seismic investigations and previous exploration drilling show the Northstar reservoir lies between 10,839 and 11,100 ft (3,304 and 3,383 m) below the sea floor. The Northstar reservoir is within the Prudhoe Bay member of the Ivishak Formation of the Sadlerochit Group, the same geologic unit that occurs onshore and which has, to date, produced more than 12.5 billion barrels of oil. The producing formation or "pay zone" is approximately 260 ft (79.2 m) thick, with an oil/water contact estimated to be at 11,100 ft (3,383 m) below the seafloor and a predicted gas/oil contact at 10,839 ft (3,304 m) below the sea floor. Sediments within the Northstar reservoir are coarser grained and more cemented, and the rock has a lower porosity and permeability than the adjacent onshore reservoir formations.

The Northstar reservoir contains an estimated 260 million barrels of original oil in place. Well tests conducted during the exploration phase, coupled with results of detailed reservoir studies, indicate that reservoir fluids from producing wells will be a combination of oil, water, and gas. Recoverable reserves are estimated to be 158 million barrels. The operational design life of the reservoir is expected to be approximately 15 years.

Oil within the Northstar reservoir is very light (42° API gravity) with a low viscosity. The oil is higher quality than the heavier oils (approximately 26° API gravity) found in adjacent onshore reservoirs. Reservoir temperature is 246 degrees Fahrenheit (119 degrees Celsius). Fluids are at high pressure (estimated in the range of 5,300 pounds per square inch) and the wells are expected to flow easily (Appendix A). Northstar Unit crude oil composition is presented in Table 4-1.

Northstar Unit Lease Stipulations: The U.S. Department of Interior (through the Bureau of Land Management and now the MMS) and the State of Alaska Division of Minerals and Energy Management (currently the ADNR Division of Oil and Gas) issued leases containing stipulations governing oil and gas exploration and development activities within the Northstar Unit.

Lease stipulations issued by the MMS pertain to oil and gas activities on the two federal leases located in the northeastern portion of the Northstar Unit. Lease stipulations issued by state agencies pertain to activities within the five lease tracts located in state waters. A summary of the state and federal lease stipulations that influence selection of alternatives for Northstar Unit development/production activities are presented below.

- Minimize the impact of industrial development on wetlands, waterfowl, and shorebirds, including restricting siting of certain facilities to the least environmentally sensitive portions of wetlands.

- Pipelines are required if a right-of-way can be identified and is technically feasible.

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- Archaeological and historical sites within the area affected by the activity must be preserved and protected.

- Areas of special biological significance must be identified, preserved, and protected.

- Gravel mining sites are restricted to the minimum number of onshore or approved offshore sites needed to develop the field efficiently with minimal environmental damage.

- Onshore pipelines should be consolidated and constructed to allow for the safe passage of caribou.

The state and federal Northstar Unit lease stipulations and restrictions for plans of operation and other terms of sale are summarized in Appendix D.

4.2.2.2 Selection of a Development/Production Location and Structure Type

Figure 4-5 illustrates the process for selecting the development/production location and structure type for the Northstar Unit. This process is described in Section 3.5. The process is applied, in conjunction with the Northstar Unit resource and site characteristics described above, in the following paragraphs.

Section 3.4 identified the current limits of directional drilling in northern Alaska as approximately 4 miles (6.4 km) from a specific surface location. Therefore, the area for potential drill sites is within an approximate 4-mile (6.4 km) radius of the most productive portion of the reservoir. Section 4.2.2.1 identified this location to be the central-southeast portion of the Northstar reservoir (Figure 4-6).

There are no onshore locations within a 4-mile (6.4 km) radius of the most-productive portion of the Northstar reservoir (Figure 4-6). Therefore, an onshore location for a development/production structure is not suitable for the Northstar Unit.

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There also are no offshore structures in useable condition (i.e., not requiring modification) within a 4-mile (6.4 km) radius of the most-productive portion of the Northstar reservoir.

A portion of Long Island, a natural barrier island, as well as the submerged remains of Northstar Island (Northstar Island shoal) and the remains of Seal Island (both man-made gravel islands) are within a 4-mile (6.4 km) radius of the most-productive portion of the Northstar reservoir (Figure 4-6). In addition, mobile bottom-founded structures, such as the Concrete Island Drilling Structure (CIDS), Molikpaq, Caisson Retained Island, and Single Steel Drilling Caisson (SSDC), could be moved to an appropriate location over the reservoir. As previously discussed in Section 3.4.2.4, all of these have served as structures to support past oil and gas exploration activities in the Alaskan Beaufort Sea. However, each of these existing offshore structures would require extensive modifications in order to serve as a long-term development/production structure.

Long Island is located in the southwest corner of the Northstar Unit and is the nearest barrier island to the Northstar reservoir (Figure 4-1). Long Island was previously used for exploratory drilling within the Northstar Unit during winter 1993/1994 (Figure 4-2). A development/production structure located on Long Island could reach only approximately 75% of the reservoir using current directional drilling technology (Figure 4-6). Moreover, Long Island is an important nesting site for common eiders, Arctic terns, and glaucous gulls (Section 6.7.1).

The Northstar Island shoal is located in the northwest corner of the Northstar Unit in approximately 43 ft (13.1 m) of water (Figure 4-1). This location has a greater exposure to dynamic ice conditions than the Seal Island location (Sections 3.4.1 and 5.6.1). If Northstar Island shoal was rebuilt to serve as a development/production structure, existing directional drilling technology could access only about 70% of the areal extent of the Northstar reservoir (Figure 4-6). In addition, directional drilling activities from this location could not reach a large part of the most productive portion of the reservoir (Figure 4-6).

Seal Island is located over the south-central portion of the Northstar reservoir, the most productive portion of the reservoir based on exploration well results (Figure 4-6). Seal Island is closer to the mainland than Northstar Island and in the floating ice zone, distant from the shear ice zone (Sections 3.4.1 and 5.6.1). If Seal Island was rebuilt to serve as a development/production structure, approximately 90% of the Northstar reservoir could be accessed using existing directional drilling technology.

The mobile, bottom-founded structures could be located 1 mile (1.6 km) northwest of Seal Island, the optimal location for reservoir access, where directional drilling could reach nearly 100% of the reservoir. Water depth at this location is approximately 40 ft (12.1 m) and it is within the floating ice zone where ice dynamics are similar to those at Seal Island. Although any of the structures, when modified, could be used in this water depth, or a new one constructed, the CIDS is the most likely candidate because of lower costs to modify it for production and less noise transmission than a steel structure (Molikpaq, SSDC).

Considering the moderate ice regime over most of the Northstar Unit, any of the island or mobile structures could be provided with adequate protection from ice impact or override. They also could all be designed to provide adequate space for drilling and production needs. Environmental concerns are raised by use of Long Island because it would mean the loss of relatively rare nesting habitat for eiders, terns, and gulls. A second environmental concern would be the higher noise levels from a steel structure. Since there are few environmental concerns about construction of a gravel island offshore, one of the gravel structures would be preferable and Long Island should be avoided. Considering cost and maximizing recovery of oil, a location at or northwest of Seal Island is most logical. The flexibility and cost savings of using a reconstructed Seal Island outweigh the benefits of locating a structure 1 mile (1.6 km) away that could reach more of the reservoir. In addition, advances in directional drilling may result in the ability to reach the entire reservoir from Seal Island within the expected lifetime of the Northstar project.

A reconstructed Seal Island, modified for ice protection and enlarged to accommodate drilling and production, will be evaluated for all alternatives for Northstar Unit development/production. Use of the CIDS or a gravel and concrete structure for additional space would be acceptable because they could be designed to withstand ice movements and because of their noise dampening characteristics. Use of the CIDS was not carried forward as a potential option for Northstar Unit development because potential benefits associated with its use would not be offset by limiting factors related to engineering and production. These factors include a relatively limited working area that would not accommodate full offshore processing of produced fluids and potential long-term maintenance requirements that would require transport of the production facilities to dry dock facilities away from the oil production area. Additionally, drilling and production operations from steel structures would result in greater transmission of sound to the environment than would occur from similar activities on a gravel island. Therefore, steel structures are not being considered as alternatives for Northstar Unit development/ production in this EIS.

4.2.3 Selection of Oil and Gas Recovery Options

Oil and gas recovery options that are available for use in the Alaskan Beaufort Sea include primary recovery, gas lift, gas cycling, waterflood, and water injection. Each of these is evaluated in the context of Northstar reservoir characteristics (Section 4.2.2.1) to determine the suitable method(s) to support oil and gas development/production activities from the Northstar Unit.

Primary Recovery: Oil and gas production through primary recovery occurs as a result of internal reservoir pressures forcing reservoir fluids to the surface (Section 3.4.2). The information presented in Sections 3.4.2 and 4.2.2, suggests that primary recovery would recover between 5% and 20% (13 million and 53 million barrels) of the estimated 260 million barrels of oil in place in the Northstar reservoir.

Gas Lift: Gas lift is most effective if a reservoir contains heavy, thick oil or if the reservoir has a high water content (Section 3.4.2). Reservoir tests conducted during the exploration phase indicate that oil within the Northstar reservoir is very light and has a low viscosity (Section 4.2.2).

Reservoir Pressure Maintenance Using Gas Cycling: Gas cycling is an effective option for oil and gas recovery from reservoirs that have a natural gas cap or that are expected to produce substantial amounts of gas, such as the Northstar reservoir (Sections 3.4.2 and 4.2.2). Based upon the results of exploration activities and reservoir modeling studies conducted by BPXA, gas cycling is expected to recover 158 million barrels (61%) of the estimated 260 million barrels of oil in place from the Northstar reservoir. Modeling shows that gas cycling would maximize recovery of oil and gas from the Northstar reservoir and makes Northstar Unit development/production economically feasible.

Reservoir Pressure Maintenance Using Waterflood: Waterflood is widely used in onshore reservoirs on the North Slope. The source of water for waterflood can be treated seawater from an intake system on Seal Island, or can be treated seawater from an existing seawater treatment plant (STP). The STP at the end of West Dock has the capacity to provide treated water to the Northstar Unit (Section 3.2.2). This would require construction of a seawater pipeline from West Dock to Seal Island.

Based upon the result of exploration activities and reservoir modeling studies conducted by BPXA, recoverable oil reserves using waterflood would be expected to be between 132 and 159 million barrels (51% and 61%) of the estimated 260 million barrels of oil from the Northstar reservoir. This is a large enough volume to make waterflood a viable recovery method for the Northstar reservoir and, if implemented, could allow the Northstar Unit development/production to be economically feasible.

Reservoir Pressure Maintenance Using Water Injection: Similar to waterflood, the source of water for water injection can be treated seawater from an intake system on Seal Island, or can be treated seawater from an existing STP. Recoverable oil reserves using water injection are expected to be between 91 and 117 million barrels (35% and 45%) of the estimated 260 million barrels of oil in place in the Northstar reservoir (Section 3.4.2). Water injection would not recover as much oil as gas cycling or waterflood and would not be as economically feasible as these two options.

Differences in environmental impacts from recovery methods are more subtle than those for other project components. There may be variations in air emissions, consumption of fuel, and wastes produced. The most obvious difference in the options discussed above, is that some require a water source and discharge and others do not. Since seawater can be used as this water source, and discharge is only backwash from the seawater intake filters, environmental impacts are likely to be minor. The major decision factors for recovery options, therefore, are cost and maximum potential recovery. Based on the discussions above, gas cycling and waterflood, which are projected to recover approximately the same amount of oil, are viable options to carry forward; however, gas cycling would be less costly, more efficient, and result in fewer environmental impacts than waterflood. Gas lift is not useful for the type of oil present, and primary recovery and water injection have recovery potentials too low to justify building the project.

4.2.4 Selection of Oil and Gas Processing Method

Oil and gas processing options that are available for use in the Alaskan Beaufort Sea include full offshore processing, partial offshore processing coupled with partial onshore processing, and full onshore processing (Section 3.4.2). These are discussed below to identify reasonable options for the Northstar Unit.

Full Offshore Processing: Full offshore processing would separate produced reservoir fluids into three product streams (sales quality crude, produced water, and natural gas). Necessary oil and gas processing equipment would be located on the gravel island and no onshore support for this activity would be required. Full offshore processing would require an island of a few acres in size to accommodate the infrastructure necessary for offshore processing. Portions of the separated gas stream could be used as a source of fuel on the island, and the remaining portion could be re-injected to support gas cycling as a method of oil recovery (Section 4.2.3). The separated water stream could be disposed of via an injection well installed on the offshore island. The crude oil could then be transported to shore without the need for further processing.

Partial Offshore Processing and Partial Onshore Processing: Partial offshore processing and partial onshore processing involve separating most of the gas and some of the water from produced reservoir fluids on the island and transporting the remaining mixture to shore for final processing. However, as indicated in Section 3.3.2, none of the onshore facilities have the capacity to fully process the volume of partially processed reservoir fluids projected to be transported from the Northstar Unit. Therefore, new processing facilities, or modifications to existing facilities, would have to be constructed to accommodate partial onshore processing of fluids produced from the Northstar reservoir. Partial offshore and partial onshore processing would require essentially the same gravel island size and the same type and amount of processing equipment, compressors, treatment facilities, pumps, and an injection well on the offshore gravel island as would the full offshore processing option.

Full Onshore Processing: Full onshore processing requires Northstar reservoir fluids to be transported by a three-phase (mixture of oil, water, and gas) pipeline to onshore facilities for processing. No processing would occur on Seal Island. However, as indicated in Section 3.3.2, none of the onshore facilities have the capacity to fully process the volume of reservoir fluids projected to be transported from the Northstar Unit. Therefore, new processing facilities, or modifications to existing facilities, would have to be constructed to accommodate the full onshore processing of fluids produced from the Northstar reservoir. Full onshore processing would require a smaller gravel island size and no processing equipment, compressors, treatment facilities, or an injection well (for produced water) on the offshore gravel island.

In summary, the partial and full onshore processing options do not appear to have environmental, technical, or cost benefits in comparison to the full offshore processing option. Although the gravel island could be smaller if all processing is done onshore, impacts to wetlands, wildlife, and hydrology from onshore expansion of facilities would be greater than impacts at an offshore site. Full processing offshore also results in an oil product that can be transported from the island by pipeline, tanker, or barge. For these reasons, full offshore processing will be carried forward as the method to be evaluated for all alternatives in this EIS.

4.2.5 Selection of Product Transportation Methods

Offshore Transportation Options: Offshore product transportation options that are suitable for use in the Alaskan Beaufort Sea were discussed in Section 3.4.2.7 and include tankers, barges, pipelines installed on gravel causeways, pipelines installed on the seafloor, and pipelines buried beneath the seafloor. Each of these are evaluated in the context of Northstar reservoir characteristics (Section 4.2.2.1) to determine the suitable methods for transporting oil from the Northstar Unit to onshore facilities.

Tankers: Oil tankers do not currently operate in the Alaskan Beaufort Sea, and no tanker facilities currently exist along the coastline to berth, load, and/or unload tankers. Seal Island is located in water depths less than 60 ft (18.3 m) and would require a dredged channel for tanker access or a pipeline from Seal Island to a tanker loading system located in water depths greater than 60 ft (18.3 m). An integrated ice management system would be required for safe transport of crude oil by tanker approximately 9 months out of the year when ice is present. If an integrated ice management system could not be successfully implemented, crude oil transportation by tanker would be limited to times of open water or very light ice conditions when tankers could operate safely. The relatively small volume of recoverable reserves from the Northstar reservoir (158 million barrels) could not economically support new facilities to accommodate tanker transport, ice management systems, or partial-year production/transport of oil.

Barges: Barge transport of crude oil from Seal Island to the Alaskan Beaufort Sea coastline would require a dredged shipping channel for barge access to the coastline, and a coastal crude oil loading/unloading facility. This would require an integrated ice management program to ensure safe transport. If an integrated ice management system could not be implemented, crude oil transport from Seal Island to the Alaskan Beaufort Sea coastline would be limited to times of open water or very light ice conditions when barges could operate safely. The relatively small volume of recoverable reserves from the Northstar reservoir (158 million barrels) could not economically support new facilities to accommodate barge transport, ice management systems, or partial-year production/transport of oil.

Pipelines Installed on Gravel Causeways: A gravel-filled causeway from the shoreline to Seal Island would extend a minimum distance of approximately 6 miles (9.6 km) offshore in water depths up to 39 ft (11.9 m). It is estimated that approximately 2 million cubic yards (yd^3) (1.5 million cubic meters [m^3]) of gravel would be necessary to construct a gravel causeway from Point Storkersen to Seal Island, and would affect approximately 95 acres (38.4 hectares) of seafloor. The causeway would be subject to erosion from ice movement and would have to be built several feet above sea level to withstand significant wave forces from severe storm events. A gravel-filled causeway of this length along this portion of the Alaskan Beaufort Sea coastline would impede nearshore water circulation patterns, nearshore sediment transport, and interfere with coastal migration of fish (Sections 5.3.1 and 6.4.1). It also would impede vessel movements associated with subsistence and commerce activities in the area. It is estimated that a gravel causeway would cost between $40 and $50 million (exclusive of any bridges) and require several months to construct.

Pipelines Installed on the Seafloor: Pipelines installed on the surface of the seafloor between Seal Island and the Alaskan Beaufort Sea coastline would be in water depths between 0 and 39 ft (0 and 11.9 m). They would be exposed to ice gouge and strudel scour events on a yearly basis during breakup. These events could rupture or damage the pipeline (Section 3.4.2.7) and cause oil spills.

Pipelines Buried Beneath the Seafloor: Pipelines must be buried to adequate depths to be protected from the effects of ice gouge and strudel scour. The project area inside the barrier islands, as well as between the barrier islands and Seal Island, is considered to be of low ice gouge intensity (Norton and Weller, 1984:202). Ice gouge survey data collected during the summer of 1995 in the project area indicated a maximum gouge depth of 2 ft (0.6 m) in water depths of 32.5 ft (9.9 m) (Leidersdorf and Gadd, 1996:1). Estimates of 100-year event ice gouge depths in the project area indicate potential gouges to depths of approximately 3.5 ft (1.1 m) (INTEC, 1997a:18-19). Surveys conducted by Leidersdorf and Gadd (1996:3) in 1995 and 1996 in the project area detected strudel scours in water depths of 6 to 20 ft (1.8 to 6 m), with maximum horizontal dimensions in the range of 20 to 70 ft (6 to 21.3 m), and a maximum depth of 4.4 ft (1.3 m). Based upon these data, offshore pipelines in the project area must be buried to depths of no less than 7 ft (2.1 m) below the seafloor (2 times the 100-year predicted ice gouge depth [Section 5.6]).

Unlike strudel scour and ice gouging, which are natural occurrences, upheaval buckling is caused by pipeline expansion, generally due to either high temperatures or pressure from within the pipeline itself. Under these circumstances, the pipeline would be subject to axial compressive loads. To relieve these loads, segments of the pipeline may shift vertically (upheaval buckling) in the trench if it is not covered sufficiently. The proposed pipeline depths, as required for protection against strudel scour and ice gouging, provide for a safety factor against upheaval buckling (INTEC, 1997b:7).

Conventional backhoe and related excavation equipment could be used from the sea ice during the winter to bury pipelines below the seafloor in water depths less than 40 ft (13 m) (Section 3.4.2.7). They also could be installed during the open water season using equipment deployed from vessels and/or barges.

<u>Double-walled Offshore Buried Pipelines</u>: The three most likely causes of a leak in a pipeline without valves and flanges (such as that proposed for the Northstar Unit) would be construction defects, corrosion, and external trauma. Control of construction defects and prevention of corrosion would be more complex for a double-walled pipeline than for a single-walled pipeline. A double-walled pipeline configuration would also require a more complex design than a single-walled pipeline and would likely present a greater chance of operational problems. A failure of the external double-walled pipeline without breaching the carrier pipe would flood the annulus with seawater. Removal of the seawater would be difficult. On the operational side, monitoring of the pipeline annulus to detect leaks would be difficult due to the length of the proposed Northstar's pipeline and associated volumes. There is currently no data available on the reliability or complexities of maintaining hydrocarbon sensors in the annulus of such a long pipeline. Based on existing information it remains unclear to what extent and to what significance these complexities and uncertainties would affect construction, installation, repair and preventative maintenance concerns. Although a double-walled pipe configuration may increase the complexity of construction, installation, and repair, a thorough analysis of the benefits and costs associated with this design alternative have not been conducted.

In determining the appropriateness and practicability of a doubled-walled pipeline alternative there remains a degree of uncertainty surrounding the issues of reliability and structural integrity. Although a cased pipeline was designed and is currently under construction for the Alpine Colville River crossing, there are significant differences in its application to subsea pipelines in an Arctic environment. Best available information is not sufficient to indicate that this (pipe-in-pipe) technology is as good or better than the proposed design for the Northstar carrier pipeline. However, the design appears to have merit in at least some specifications and warrants further consideration and analysis in future potential applications.

In summary, for cost, environmental, and safety reasons, as well as their limited season of usefulness, transport by tankers or barges does not appear to be a desirable option. Risks to the environment from oil spills would be greater, with no advantages in reduced impacts elsewhere. However, a pipeline could not simply be installed on the surface of the seafloor. Protection by burial would be necessary for the entire distance between Seal Island and the shoreline. Burial within a gravel-filled causeway would be acceptable only if enough breaches were included to provide for water circulation and fish and boat passage. Because the structure would need to cross Gwydyr Bay, which is used by both fish and birds, bridges may be needed for up to half of the causeway length. This would be expensive, in addition to the cost of the gravel. One-time burial of a pipeline would have fewer adverse impacts than repeated dredging of a shipping channel or placement and maintenance of a causeway. Therefore, for both cost and environmental reasons, burial beneath the seafloor appears to be the best option. Burial depths and other pipeline design features must consider ice gouging, strudel scour, and thawing and subsidence in the permafrost transition zone (Sections 5.3 and 5.6) to ensure that the pipeline is stable and safe. A variety of buried pipeline routes between Seal Island and the shoreline will be evaluated as alternatives for Northstar Unit development/production (see below).

Pipeline Landfall Options and Offshore Pipeline Corridor Alignments: The use of pipelines to transport oil from Seal Island to the Alaskan Beaufort Sea coastline requires that the offshore pipeline transition from beneath the seafloor to land at the coastline. Pipeline landfalls can be located along a natural coastline or at an existing manmade facility. The criteria for determining suitable landfall location(s) are discussed in Section 3.4.2.7. Pipeline landfall locations must be selected in conjunction with selecting the offshore pipeline corridors between Seal Island and the coastline. Criteria for determining offshore pipeline alignments also are discussed in Section 3.4.2.7.

Application of these criteria to the Northstar project area determined that there is no single landfall and offshore pipeline corridor combination that best satisfies all items in the lists of criteria. Offshore pipeline corridor and landfall locations that best satisfy their respective criteria are discussed in Section 3.4.2.7. Those options that represent a reasonable range of options for transporting crude oil from Seal Island to a landfall location and gas from a landfall location to Seal Island are shown on Figure 4-7 and are identified as follows:

- An offshore pipeline corridor extending south from Seal Island to landfall at Point Storkersen. This offshore corridor and landfall option has the shortest possible offshore pipeline corridor length, avoids high value habitat, avoids known cultural or archaeological sites, and minimizes pipeline bends (Alternatives 2 and 3).

- An offshore pipeline corridor extending south from Seal Island until it intersects the southern boundary of the Northstar Unit. The corridor then turns southeast toward West Dock, staying north of Stump Island. At the southeast end of Stump Island, the corridor turns southwest, making landfall along the coastline between Point McIntyre 1 (PM1) and the West Dock causeway. This offshore corridor and landfall option avoids proximity to river deltas, which minimizes potential impacts from strudel scour, avoids high value habitat, avoids cultural or archaeological sites, and allows access/connection to existing onshore oil and gas facilities (Alternative 4).

- An offshore pipeline corridor extending south from Seal Island until it intersects the southern boundary of the Northstar Unit. The corridor then turns southeast toward West Dock, staying north of Stump Island and continuing eastward until it intersects the West Dock causeway. Landfall is shown at Dock Head 2, just landward of the 650-ft (198 m) breach; however, this site should be considered representational of any West Dock causeway landfall. A landfall seaward of the breach would require placing Northstar pipeline(s) on the causeway bridge, which may increase costs. A landfall further landward of Dock Head 2 would increase the subsea length of buried pipe, but would decrease the length of required causeway widening (see Section 4.4.5). This offshore corridor and landfall option avoids proximity to river deltas, high value habitat, near surface subsea permafrost, eroding shoreline, and cultural or archaeological sites. It also allows access/connection to existing onshore oil and gas facilities (Alternative 5).

Onshore Pipeline Corridor Alignments: Once the offshore pipelines from Seal Island reach landfall, they transition to onshore pipelines. Onshore pipelines would be elevated along vertical support members (VSMs) and would cross undeveloped tundra or follow established pipeline corridor(s) to the Central Compressor Plant (CCP) (gas line) and Pump Station No. 1 (oil line). The criteria for identifying new onshore pipeline corridors that cross undeveloped tundra are presented in Section 3.4.2.7.

There is no single onshore pipeline corridor that satisfies all of the criteria described in Section 3.4.2.7. Onshore pipeline corridors that best satisfy these criteria and that represent a reasonable range of options for connecting the landfall locations to Pump Station No. 1 and the CCP are shown on Figure 4-7 and described as follows:

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- A new oil and gas pipeline corridor from the Point Storkersen landfall continues south to a point where the gas pipeline turns east and follows existing road and pipeline corridors to the CCP. The oil pipeline continues south along a combination of new and existing pipeline corridors, crosses the Putuligayuk River, and connects to Pump Station No. 1. This alignment (Alternative 2) minimizes total pipeline length and costs, avoids high value fish and wildlife habitat (although less so than the other alternatives), and avoids conflicting land uses.

- A new oil and gas pipeline corridor from the Point Storkersen landfall turns east until it intersects the existing pipeline corridor between PM1 and the West Dock Staging Pad. From that intersection, the oil and gas pipelines parallel existing pipeline corridor to the West Dock Staging Pad, then turn south following an existing pipeline and roadway corridor to the CCP, where the gas pipeline terminates. The oil pipeline continues in a southwesterly direction along a combination of new and existing pipeline corridors, crosses the Putuligayuk River, and connects to Pump Station No. 1. This alignment (Alternative 3) avoids high value fish and wildlife habitat and avoids conflicting land uses.

- The oil and gas pipeline corridor continues from a landfall location midway between PM1 and the West Dock Staging Pad where it parallels an existing pipeline corridor to the West Dock Staging Pad. From the West Dock Staging Pad, the oil and gas pipelines turn south, paralleling existing roadway and pipeline corridors to the CCP, where the gas pipeline terminates. The oil pipeline continues in a southwesterly direction along a combination of new and existing pipeline corridors, crosses the Putuligayuk River, and connects to Pump Station No. 1. This alignment (Alternative 4) maximizes use of existing disturbed areas, avoids conflicting land uses, and avoids high value fish and wildlife habitat.

- The oil and gas pipeline corridor continues from the landfall on the West Dock causeway, paralleling the causeway to the West Dock Staging Pad. The oil and gas pipelines then parallel existing pipeline and roadway corridors from the West Dock Staging Pad south to the CCP, where the gas pipeline terminates. The oil pipeline continues in a southwesterly direction along a combination of new and existing pipeline corridors, crosses the Putuligayuk River, and connects to Pump Station No. 1. This alignment (Alternative 5) maximizes use of existing disturbed areas, avoids conflicting land uses, and avoids high value fish and wildlife habitat.

4.2.6 Gravel Source Options

Gravel would be necessary for gravel island reconstruction, gravel pads, as an aggregate material for concrete, and as backfill material for pipeline installation at landfall locations. In addition, gravel may be required for new roads, causeway widening, and construction of caribou and road crossings. The largest volume would be several hundred thousand cubic yards for reconstruction of Seal Island for use as a development/production structure.

Existing gravel at Seal Island should be re-used to the extent practical to minimize additional mining impacts as well as hauling costs. Additional gravel to support construction needs could be obtained from other offshore gravel sources, such as abandoned manmade gravel islands, barrier islands, or from suitable seafloor deposits. Gravel also could be obtained from active onshore gravel mine sites, or from a newly developed gravel source.

Offshore gravel sources, such as other existing manmade gravel islands or gravel/rocky seafloor deposits, may provide valuable substrate for marine organisms. These sources would require excavation and transport to the new location which may result in increased turbidity during excavation, and noise impacts (vessel movement and loading, dredging) which could affect wildlife and fisheries resources in the area. Northstar Island shoal is the only known offshore source of gravel in the area. Summertime excavation and relocation of this gravel from Northstar Island shoal to Seal Island could be disruptive to both whale migration and subsistence hunting due to its location near the migration corridor. Winter removal of gravel from Northstar Island shoal would require that dredging operations be conducted from the ice surface. This activity would be time consuming and costly.

Offshore barrier islands in the Northstar Unit area are long and narrow and have low elevations, typically less than 10 ft (3 m). Many of these islands provide a limited type of nesting habitat for migratory birds, and gravel removal from these islands could adversely impact this habitat. It also could prove difficult to develop a gravel mine pit on a barrier island that extends below sea level, since the pit may fill with seawater. In addition, blasting frozen gravel, if required, would adversely affect fish and birds during spring and summer and could also create a deep pit in shallow water which could trap fish over the winter.

There are seven active onshore gravel mine sites in the North Slope oil fields (Figure 4-8). The closest active gravel mine to Seal Island is the Kuparuk Deadarm mine site, located in the Prudhoe Bay Unit. Mining several hundred cubic yards of gravel from this site would require removal of approximately 625,000 yd^3 (477,800 m^3) of tundra overburden (BPXA, 1997b:7.6-1). Additional, smaller quantities of gravel also could be obtained from the existing, permitted Put 23 Oxbow (Put 23) mine site near the mouth of the Putuligayuk River (Figure 4-8). These sites could be used as a primary gravel source in the event that a new gravel source for island construction could not be permitted or was determined to be inadequate. These two sites also could be used as a gravel source for island maintenance after it is constructed.

As an alternative to using existing onshore mine sites, a new site may be identified, especially if haul distances to existing sites are long. A new gravel mine site near the mouth of the Kuparuk River is proposed by BPXA as a source of gravel to reconstruct Seal Island. The site is close to Seal Island in a region of riverine barrens and floodplain alluvium (BPXA, 1997b:7.2-1) with little overburden. Winter mining and hauling activities would not interfere with either the spring or fall bowhead whale migration offshore of the project area. The mine site would only be used during one winter season and would be rehabilitated to provide shallow and deep water habitat for fish once mining activities have been completed. The general quality of the gravel is not as well known as that from an existing source. This location would require construction of an onshore ice road for approximately 2 miles (3.2 km) on the river from the mine site to the river mouth. Because the ice road would be used only one winter, no permanent road would be necessary. An advantage of the single winter

Figure 4-8 (page 1 of 2)

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season use is that rehabilitation work would be completed quickly. In contrast, other large existing mine sites may be in use for 10 to 20 years before decommissioning and rehabilitation..

Considering the adverse impacts of mining either a natural barrier island or an abandoned, manmade island, onshore gravel sources appear to be preferable. Among the onshore sites, any of the active mine sites (e.g., Put 23 Oxbow, Kuparuk Deadarm) are available, and their use during winter would result in little negative impact. The proposed new mine site in the Kuparuk River delta is preferable for economic reasons and because rehabilitation work would return the site to usable habitat more quickly than would occur at other mine sites.

4.2.7 Spoils Disposal Options

Installation of pipelines between Seal Island and onshore facilities would necessitate burying the pipe beneath the seafloor to sufficient depths to avoid ice gouging and strudel scour damage. Pipeline burial requires digging a trench into the seafloor and placing pipe into the trench; then refilling the trench with previously removed sediment. However, not all removed sediment would be returned to the trench, particularly where the trench is excavated through bottomfast ice. In these areas, the trench walls are vertical (like the slot cut through the ice) and the return of all the removed sediments would create a mound higher than the original bathymetric contours. In shallow waters, this could adversely impede water circulation, fish movements, and boat operations. Although this mound would be expected to be smoothed and redistributed by natural ice and oceanographic processes over several years, the risk of short-term adverse impacts can be reduced by disposing some of the sediments at other locations.

In the landfast ice zone, in water depths greater than about 6 ft (1.8 m) (floating-fast ice), seabed sediments remain unfrozen. Trenches in these water depths will have sloped walls due to sloughing. Excavated material refilling these sections could also create a temporary mound over the pipeline trench. Because the water is deep, this mound would not adversely impede water circulation, fish migration, or boat operations. Ocean currents and ice activity would disperse these spoils relatively quickly.

In both cases, sediments not returned to the pipeline trench are termed excess spoils and must be disposed in an acceptable manner. Approximately 5,000 yd^3 (3,823 m^3) of excess spoil would need to be disposed for a buried pipeline between Seal Island and the shoreline. Disposal options for such material include:

- Onshore disposal.
- Offshore disposal in the bottomfast ice zone.
- Offshore disposal in the floating-fast ice zone.

For the onshore disposal option, excess spoil material would be salty and of little or no use for revegetation purposes. Because it is mostly fine material, it is also not of value as construction fill. It could also contaminate areas outside the disposal site if salt leaches into surrounding areas. Therefore, onshore disposal of excess spoil material is not a reasonable option.

Although disposal of spoils on bottomfast ice provides a more stable surface for trucking and handling of excavated material, water depth is insufficient to provide adequate dispersion of the spoils over a large area as the ice breaks up in the spring. In Gwydyr Bay and other nearshore lagoons, weaker currents inhibit soil dispersion making these areas unsuitable for spoil disposal.

Disposal in waters with floating-fast ice provides enough water depth for dispersion of the spoils as the ice melts, although some ice thickening may be required for haul road stabilities. Moreover, if the disposal area is beyond the barrier islands, stronger currents are available to further disperse the excess spoils as the ice breaks up in the spring. The offshore location(s) should be selected away from sensitive habitats (e.g., the Boulder Patch). In addition, location(s) that would reduce distance should be used, if possible. Disposal in areas with water depths greater than 65 ft (19.8 m) is impracticable due to the long haul distances. This area is also likely to contain ice ridges, making travel difficult and unsafe.

The preferred excess spoils disposal area(s) are regions of floating-fast ice either outside the barrier islands or along the thickened area adjacent to the ice slot (Section 4.4.2.2). Regardless of the option(s) selected, spreading of the excess spoil material to not more than 1 to 2 ft (0.3 to 0.6 m) thick over the ice would prevent large piles of material from being deposited on the seafloor once breakup occurs.

4.2.8 Construction Schedule Options

Alaska's Arctic Coastal Plain and Beaufort Sea environments are harsh, with extreme cold and a period of continuous darkness during the winter. Summers are warmer, with periods of continuous daylight. These seasonal variations can influence the nature and severity of impacts associated with construction of oil and gas development/production facilities in this area.

Gravel mining in the river channels and/or floodplain in the winter when rivers are frozen avoids disturbances to fish and their habitat, which could occur during the warmer summer months. Use of onshore ice roads for gravel hauling and pipeline installation during the winter months also minimizes impacts to tundra habitats, compared to the construction of permanent gravel roads. Offshore vessel activities and related noise impacts during open water season may impact bowhead whales and migratory birds. For these reasons, the winter season is the preferred alternative (when compared to the summer season) for conducting gravel mining, hauling, and placement for island construction, as well as onshore and offshore pipeline installation.

Some island construction activities, such as island slope grading and installation of island slope protection, would be done during the open water season because sea ice would hinder the efficiency and safety of these activities. In addition, gas compression and process modules and other equipment, which are too heavy for safe transport over offshore ice roads, would require transport to Seal Island by barge and/or vessel during the open water season.

Offshore construction activities, when conducted during the open water season, should be conducted in a manner that minimizes disturbance to the bowhead whale migration that occurs through the project area during the spring and fall.

4.3 ALTERNATIVES CONSIDERED BUT ELIMINATED FROM DETAILED ANALYSIS

Oil and gas technologies applicable to development/ production in the Alaskan Beaufort Sea, based on the discussion in Chapter 3, were evaluated in Chapter 4 to identify those appropriate for the Northstar Unit. Options for project components that were eliminated from further evaluation, and the reason(s) for elimination, are identified below.

Development/Production Location and Structure Type (Section 4.2.2.2):

- Onshore.
  - Too far to reach Northstar reservoir from onshore.
- Barrier islands.
  - Have high value as nesting habitat.
  - Too far from Northstar reservoir.
- Northstar Island shoal.
  - Cannot reach enough of Northstar reservoir.
  - Exposure to larger ice movements than sites closer to shore creates high risk to facilities.
- New location within 4 miles (6.4 km) of most productive portion of the Northstar reservoir.
  - Cost cannot be justified by additional oil reached (versus Seal Island location).
  - Likelihood for extending current limits of directional drilling from Seal Island in future.
- Molikpaq, CIDS and SSDC.
  - High costs for modifications.
  - Greater underwater transmission of noise.
- Subsea silos and caverns.
  - High cost.
- Seafloor templates.
  - Water depth too shallow.
- New purpose-built structure.
  - Higher cost and longer lead time than modifying existing structures.

Oil and Gas Recovery Options (Section 4.2.3):

- Primary recovery.
  - Not economic (5% to 20% recovery).
- Gas lift.
  - Not appropriate because of composition of Northstar reservoir fluids.
- Water injection.
  - Not economic (35% to 45% recovery).
- Waterflood.
  - STP required.
  - Marine discharges of filtrate.

Oil and Gas Processing Options (Section 4.2.4):

- Partial offshore and partial onshore processing.
  - Results in greater negative impacts to wildlife and habitat due to expansion of onshore facilities.
- Full onshore processing.
  - Results in greater negative impacts to wildlife and habitat due to new onshore facilities.
  - Difficult to transport three-phase fluids.

Product Transportation Options (Section 4.2.5):

- Tankers and barges.
  - Greater spill risk than pipelines.
  - High costs due to additional facilities needed.
  - Repeated dredging required.
- Pipeline installed on the surface of the seafloor.
  - High risk of damage by ice or ship anchors.
- Pipeline buried in gravel causeway.
  - Significant negative impacts to water circulation movements.
  - High cost to construct, especially with adequate breaches/bridges.
- Double-walled pipe.
  - Available information is not sufficient to indicate that double-walled pipe is as good or better design than a single-walled pipe.
  - Control of construction (welding) defects and prevention of corrosion would be more complex for a double-walled pipe.
  - Double-wall pipe would also involve numerous installation constraints that could limit or prohibit single season construction.
  - Repair of a damaged double-walled pipeline would be more difficult than repairing a single-walled pipeline.

Offshore Pipeline Route and Landfall Options (Section 4.2.5):

- Route straight to West Dock.
  - Longer distance in water depths greater than 10 ft (3 m).
- Landfall location outside the Point Storkersen to West Dock range.
  - Need for gas from onshore could result in two separate pipeline routes.
  - No excess capacity at facilities near landfall to support Northstar processing.
  - Longer pipeline distances increase risk of pipeline spills and increase costs.
- Other landfall locations between Point Storkersen and West Dock.
  - Some areas of high value saline marsh to be avoided.

Onshore Pipeline Route Options (Section 4.2.5):

- Other angled routes between Point Storkersen landfall and closest pipe/roads.

  - Pipeline would cross more ponds and high value basin-wetland complexes.
  - Pipeline would disrupt more undeveloped tundra.
- Other routes through oil field following existing roads and pipelines.
  - Many variations possible, most are more complex and longer.

Gravel Source Options (Section 4.2.6):

- Offshore sites.
  - None known within any reasonable distance of the Northstar Unit.
  - Negative impacts to marine mammals and other organisms may be significant.
- Reuse of gravel islands.
  - Use of Northstar Island shoal would be disruptive to whales.
  - Use of Northstar Island shoal would be logistically difficult.
  - No other islands are within a reasonable distance of the Northstar Unit.

Spoils Disposal Options (Section 4.2.7):

- Onshore.
  - Saline material not acceptable for use onshore as it kills terrestrial vegetation.
- Shallow water (bottomfast ice) within lagoons.
  - Additional sediments could block water circulation and navigation in depths less than 4 ft (1.2 m).
  - Few areas deeper than 4 ft (1.2 m).

Construction Schedule Options (Section 4.2.8):

- Summertime trenching and pipe laying.
  - Environmental impacts increase greatly due to presence of whales, seals, fish, and birds.
  - No storage space for excavated trench material for backfilling.
  - Very limited work season, potentially none at all if ice does not leave the area.

4.4 ALTERNATIVES SELECTED FOR EVALUATION IN THIS EIS

A broad range of oil and gas technological options were evaluated to identify those that are applicable for long-term development/production in the Alaskan Beaufort Sea (Chapter 3). Technological options identified were then evaluated in Section 4.2 to determine which are applicable for the Northstar Unit. Selected project components are listed below, along with the most important criteria used for selection.

Oil and Gas Drilling Methods (Section 3.4.2.3):

- Directional drilling.
  - Only one development/production structure required.
  - Can reach most of reservoir from one location.

Development/Production Location and Structure Type (Section 4.2.2.2):

- Reconstructed gravel Seal Island.
  - Much of gravel volume is already in place.
  - Lowest noise transmission of all structure types.
  - Can withstand ice movements.
  - Can reach most of reservoir.

Oil and Gas Recovery Options (Section 4.2.3):

- Gas cycling.
  - 61% recovery predicted.
  - Appropriate for reservoir and supplemental gas available.

Oil and Gas Processing Options (Section 4.2.4):

- Full offshore processing.
  - Keeps more impacts offshore where less habitat and fewer wildlife are disturbed.
  - Allows transport of more stable, safer product.

Product Transportation Options (Section 4.2.5):

- Buried subsea pipeline.
  - Safest option with few direct impacts.

Offshore Pipeline Route and Landfall Options (Section 4.2.5):

- Shortest route between Seal Island and 10-ft (3 m) contour.
  - Minimizes exposure to large ice floes.
  - Minimizes need for slower, deeper water construction method.
- Straight route to Point Storkersen landfall.
  - Minimizes pipeline lengths.
  - Minimizes exposure to ice outside the barrier islands.
- Eastern route to landfall near Point McIntyre.
  - Smaller impacts to undisturbed tundra habitat at landfall.
- Eastern route to landfall on West Dock.
  - Avoids crossing permafrost transition zone.

- Avoids all impacts to undisturbed tundra habitat at landfall.

Onshore Pipeline Route Options (Section 4.2.5):

- Route straight to Pump Station No. 1 from Point Storkersen.
  - Minimizes pipeline length.
- Eastern route from Point Storkersen to Point McIntyre.
  - Less impact to undisturbed tundra.
  - Allows for future development to west or offshore to join pipeline corridor.
- Route from Point McIntyre to West Dock Staging Pad.
  - Even less impact to undisturbed tundra.
  - Valve station and onshore pipeline accessible by road.
- Route from West Dock Staging Pad to the CCP and Pump Station No. 1.
  - Maximizes use of existing disturbed areas.
  - Valve station and almost all onshore pipeline accessible by road.

Gravel Source Options (Section 4.2.6):

- Use and rehabilitate new site in Kuparuk River delta.
  - Sparsely vegetated site with little overburden to move and replace.
  - Close distance to Seal Island.
  - Single winter use results in rapid rehabilitation and no permanent roads.
- Use of Kuparuk Deadarm mine site.
  - Backup source if new site cannot be used and source for additional gravel needs (maintenance, caribou crossings).
- Use of Put 23 Mine site.
  - Backup source for additional gravel needs.

Spoils Disposal Options (Section 4.2.7):

- Offshore in the floating-fast ice zone and outside the barrier islands.
  - Achieves good dispersion of waste material.

Construction Schedule Options (Section 4.2.8):

- Winter trenching, pipeline construction, and gravel haul and placement.
  - Minimizes impacts to bowhead whales, vegetation, fish, and birds.
  - Minimizes water quality impacts (turbidity).

The selected options were combined to describe four action alternatives for the Northstar Project. A No Action alternative is also considered for comparing and evaluating potential impacts of the action alternatives in Chapters 5 through 9. The alternatives discussed in the following sections are:

- Alternative 1 - No Action
- Alternative 2 - Point Storkersen Landfall/BPXA's Proposed Action
- Alternative 3 - Point Storkersen Landfall to West Dock Staging Pad
- Alternative 4 - Point McIntyre Landfall to West Dock Staging Pad
- Alternative 5 - West Dock Landfall

4.4.1 Alternative 1 - No Action

Northstar Unit development/production would not occur at this time or by the proposed methods under the No Action Alternative. The remains of Seal Island would not be reconstructed and would continue to erode in accordance with approved abandonment plans. Onshore and offshore pipelines between Seal Island, Pump Station No. 1, and the CCP would also not be constructed, and a nominally estimated 158 million barrels of recoverable reserves from the Northstar reservoir would remain in place. The offshore and onshore environments (Figure 4-9) would be expected to continue to experience fluctuations in population and habitat quality in a manner similar to that which has occurred in previous years.

4.4.2 Alternative 2 - Point Storkersen Landfall/BPXA's Proposed Action

4.4.2.1 Overview of Proposed Action

The Applicant's preferred alternative (BPXA's proposed action) includes a self-contained offshore development/production facility in 39 ft (11.8 m) of water approximately 6 miles (9.6 km) offshore of Point Storkersen in the Alaskan Beaufort Sea. The facility would be located on a gravel island constructed over the remains of Seal Island.

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Seal Island's reconstructed working surface (top) dimensions would be 465 by 421 ft (141.7 by 128.3 m) to accommodate drilling, processing equipment and facilities, a personnel camp, and supporting infrastructure. The island would have a sheet pile perimeter wall surrounding the island work surface to protect the island from natural forces. A 315-ft (96 m) long barge dock is planned for the south side of the island to allow access onto the island surface for the drilling rig, processing equipment, and supplies. A submerged gravel berm 50 to 100 ft (15.2 to 30.5 m) wide would be placed around the west, north, and east sides of the island. The surface of the submerged berm would be at 15 ft (4.6 m) below mean lower low water (MLLW). This submerged berm would break large incoming waves, reduce the force of waves against the sheet pile wall, and minimize wave overtopping. This submerged berm would also help prevent thick, multi-year ice floes and ridges from contacting the concrete mat armor on the island slopes. The submerged berm may erode or be damaged during major storm events. It would be inspected and maintained as needed. The total sea bottom footprint acreage of the proposed island would be approximately 18.1 acres (7.3 hectares); however, this acreage may increase to about 20 acres (8 hectares) as a result of side slope and/or submerged berm material being redistributed by current, wave, and ice forces.

Gas cycling is the preferred oil recovery method for depleting the Northstar reservoir. The reinjected gas allows a greater volume of oil to be produced. Approximately 100 million standard cubic feet (2.83 million m^3) per day of natural gas would be sent via a subsea pipeline from the CCP located onshore in the Prudhoe Bay Unit to Seal Island to assist with the gas cycling process.

Two pipelines between Seal Island and existing onshore facilities would be constructed. These pipelines would follow onshore and offshore pipeline alignments identified in Section 4.2.5, and are described below.

- One 10-inch (25 centimeter [cm]) common carrier pipeline from Seal Island to Pump Station No. 1 to transport sales quality oil that meets delivery specifications for delivery to the Trans Alaska Pipeline System.

- One 10-inch (25 cm) common carrier gas pipeline from the CCP located onshore in the Prudhoe Bay Unit to Seal Island to transport high-pressure gas to the island to assist with the gas cycling process.

These pipelines would be buried in a trench approximately 6 ft (1.8 m) below the seafloor between the coastline and the barrier islands and from 7 to 9 ft (2.1 to 2.7 m) below the seafloor between the barrier islands and Seal Island. More detailed pipeline corridor information for this alternative is presented in Table 4-2. The offshore and onshore pipeline alignment is shown on Figure 4-10.

4.4.2.2 Proposed Construction Activities

Freshwater Sources for Ice Road Construction: Permitted freshwater sources in the project area are shown on Figure 4-8. Many of these sources are not useable during the winter because they are too shallow and either freeze, or nearly freeze, solid. The Kuparuk Deadarm mine site (Permit No. ADL

75979), located approximately 5 to 6 miles (8 to 9.7 km) up the Kuparuk River, would be the most probable source of

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freshwater for ice road construction associated with the Northstar Development Project. The Kuparuk Deadarm mine site is within 3 miles (4.8 km) of BPXA's proposed Northstar gravel mine location in the Kuparuk River delta and could be accessed by an ice road on the Kuparuk River. Although the Kuparuk Deadarm source has fish in it, it is a deep source that is currently permitted for removal of up to 100 million gallons (378.5 million liters) of water per year. This source is replenished each year during breakup.

Ice Road Construction: An ice road would be constructed over sea ice from the West Dock causeway to the mouth of the Kuparuk River, and then up the Kuparuk River approximately 2 miles (3.2 km) to the proposed gravel mine site. A second ice road would be constructed from the mine site to Seal Island (Figure 4-11). Gravel from the new gravel mine site would be used to reconstruct Seal Island. Additional ice roads paralleling the onshore pipeline alignment and along existing onshore pipelines would be constructed for onshore pipeline construction activities.

The offshore ice roads would be built as approximately 200-ft (61 m) wide ice platforms. Construction would start in early December and occur 24 hours a day, 7 days a week. Work would stop only during unsafe conditions, such as high winds or extremely low temperatures. In water deeper than 10 ft (3 m) the ice needs to be approximately 8 ft (2.4 m) thick to support construction equipment. Seawater for thickening the offshore ice would be obtained by drilling holes through the existing sea ice and pumping salt water to the surface using specially designed rolligon pumps. The top layer of onshore and offshore ice roads would be made from freshwater. Following construction, ice roads would be maintained using graders with snow wings and blowers. Ice road travel is usually not safe after the first part of May. Ice road construction crews would be housed at existing facilities in the Prudhoe Bay area and transported by bus to the work site for each shift.

Onshore pipeline construction activities would be performed from the surface of existing gravel roads/pads, frozen lakes, and/or ice roads and pads. Ice roads would be built approximately 130 ft (39.6 m) wide and would be constructed with sufficient thickness to protect the tundra. Ice pads would be made by the use of snow and spraying freshwater over the surface of the frozen tundra and would be large enough for construction vehicle traffic. Construction of the ice roads and pads would take place in January and February. Figure 4-12 provides details of a typical cross-section of an onshore ice road on which the construction activities will be performed.

Reconstruction of the Existing Seal Island: A plan view of the reconstructed Seal Island is shown on Figure 4-13, and two cross-sections, one looking east and another looking north, are shown on Figures 4-14 and 4-15, respectively. The reconstructed gravel island would be designed to accommodate the following oceanographic parameters:

- Water level fluctuations of 4 ft (1.2 m) above MLLW.
- Significant wave heights of 20 ft (6 m).
- A maximum of 7.5 ft (2.3 m) thick, rafted and ridged first-year ice.
- Surface currents of 4 knots (7.4 km per hour) as a result of storm-generated sustained winds of 60 knots (111 km per hour).

A more detailed presentation of the oceanographic design criteria and wave and ice force considerations is provided in Tables 4-3, 4-4, and 4-5.

Gravel Mine Pit Development: Gravel for reconstruction of the island would be hauled from a new gravel mine site to be developed near the mouth of the Kuparuk River (Figures 4-11 and 4-16). On completion of mining activities, an approximately 6-ft (1.8 m) deep breach would be constructed at the eastern end of the pit to connect the mine site to the Kuparuk River. The bottom of the breach would be excavated to a level approximately 2 ft (0.6 m) below the mean low water line of the river. During spring, the Kuparuk River would begin breakup in its headwaters and flow would proceed down river. As the melt water reaches the sea ice, it would begin to backup and flood the lower reaches of the river. This back flow would begin to fill the excavated mine site. As breakup continues, the flooded mine site water elevation would reach a point of equilibrium with the Kuparuk River. It is anticipated that this would occur sometime during the first spring and summer following mine site closure.

Completion of the mining and rehabilitation plan would create an approximately 30-acre (12 hectare) combination shallow water/deep water lake with approximately 4 acres (1.6 hectares) of shallow littoral area along the south side of the site. Shallow littoral areas would be approximately 6 ft (1.8 m) deep with the rehabilitated mine site's deepest point being approximately 40 ft (12 m) deep.

Due to its proximity to Gwydyr Bay, the rehabilitated mine site would become brackish. It is anticipated to be useful as anadromous fish habitat. Fish access to the pit would be provided by the breach excavated at the northern end of the pit.

Under a single season construction schedule, all gravel (for island, valve pads, and pipe placement at the landfall) would be obtained from the new mine site. The pit would be mined on a one-time basis during the winter of project construction and would serve as the primary source of construction material for the island. Gravel needed for summer construction activities would be obtained from either the Put 23 mine site or the Kuparuk Deadarm mine site. These include small volumes for placement of the oil and gas pipelines within existing caribou and road crossings, or for maintenance and repairs.

Under a two season construction schedule, only gravel for the island would be obtained from the new mine site, since the new mine site would be flooded at first season breakup and therefore would not be available for future use. Gravel for two new valve pads (one at the landfall and one adjacent to the CCP) and for the Point Storkersen pipeline approach, would be obtained from either the Put 23 or the Kuparuk Deadarm mine site. Gravel would also be obtained from these sources, if necessary, for placement of the pipelines within existing caribou and road crossings during the summer prior to pipeline construction.

Gravel Haul and Placement: Approximately 400,000 to 500,000 yd^3 (306,000 to 382,000 m^3) of existing gravel remains at Seal Island. Approximately 700,000 to 800,000 yd^3 (535,185 to 612,640 m^3) of additional gravel would be excavated from the gravel mine site and hauled to the island by ice road. Gravel would be hauled in large volume trucks from the gravel mine site to a temporary stockpile and reload (staging) area

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inside the barrier islands on bottomfast ice (Figure 4-11). This staging area would be necessary because lighter dump trucks must be used to transport gravel to Seal Island over the floating landfast ice. The dump trucks would deposit loads on the existing Seal Island surface.

Island Construction: The working surface of the island would be a rectangle surrounded on all four sides by sheet piling. The sheet pile wall would be designed to carry the loads of the gravel and water behind it, and surface loads placed on top of the gravel (loads up to 600 pounds per square ft of area). On the west side of the island where storms are most intense, the wall will rise to an elevation of 27 ft (8.2 m) above MLLW. On the east side of the island, the wall will rise to an elevation of 21 ft (6.4 m) above MLLW. Open-cell sheet pile construction would be used on the south side of the island for the dock area. The top elevation of the sheet piles along a section of the dock face would be 7 ft (2.1 m) above MLLW to allow barge docking and roll-off of loads onto the island. The sheet pile wall would be installed between March and May, before the submerged gravel berm is shaped and the concrete mats are placed. The sheet pile perimeter wall surrounding the island work surface would be untreated steel that would weather to a natural rust color. Island slopes would be graded and contoured to the general shape shown on Figure 4-17 during the subsequent open water season prior to installation of a linked concrete mat armor island slope protection system. The linked concrete-mat armor would consist of a series of concrete blocks approximately 4 by 4 ft by 9 inches (1.2 m by 1.2 m by 23 cm) thick with 1 inch (2.5 cm) integral spacers. The blocks will be both square (approximately 9,500 total) and corner trapezoids (approximately 5,800 total). Figure 4-18 provides details of a typical square block layout.

A block plant would be set up in a Deadhorse yard for fabrication of these blocks. Cement and required additives would be trucked from Anchorage. The concrete aggregates would be mined in the Put 23 mine site on the North Slope. Water would be obtained from permitted sources shown on Figure 4-8. The blocks would be stored outside until they are transported to Seal Island via ice road or barge.

Prior to concrete mat placement, a highly permeable fabric liner would be placed on the island's gravel slope down to the -20-ft (-6 m) MLLW depth to help prevent erosion of fine sediments into the water column following island construction. Cranes would be utilized for setting concrete mats below the water surface. Divers would adjoin mat sections. The concrete armor would be connected to the sheet pile wall with shackles, chain linked to steel angle iron welded to the base of the sheet pile wall. Blocks which are damaged during the construction phase would be hauled back to shore for disposal in an approved disposal site.

The heaviest loads to be supported on the island are the process and the gas compression, personnel accommodation, and warehouse modules. The drilling rig provides its own foundation support through its own substructure. Concrete foundation footings would be installed on the island surface to provide sufficient foundation support for these modules.

During island construction, a 15-ft (4.6 m) wide trench leading from the south side of the island would be built with additional sheet piling to assist with pipeline installation on the island. A seawater intake structure would be installed below the water line along the island's dock face during island construction (Figure 4-19). The intake structure would be designed to withstand impact from rubble ice and configured to limit flow velocities to acceptable levels.

Installation of Island Facilities: The process and gas compression modules would be constructed at the Port of Anchorage, transported via ocean-going barges, and installed on Seal Island. These modules would be the facilities where produced oil, water, and gas are separated and power for the island is generated. In addition to these modules, a permanent quarters module, other operations support facilities, and drilling-related equipment would be installed on the island. Drilling-related equipment includes a dedicated drilling rig. Operations support facilities include a module which contains the potable water system, emergency power generation, and wastewater management facility. A pre-fabricated, modular tank farm would also be installed that would be comprised of two insulated tanks, one 2,100-barrel potable water tank, and one 2,800-barrel diesel storage tank. All of these modules and equipment would be transported to Seal Island by barge during the ice-free season (August to September). Module walls, buildings, and storage containers would be painted beige, and exposed module steel would be painted gray.

A 55- by 62-ft (16.8 by 19 m) platform located on the southwest corner at the island would be designated for landing helicopters (Figure 4-13). It would be capable of handling up to a Sikorsky 76A or Bell 212 helicopter.

A 215-ft (65.5 m) high cantilevered flare tower would be located in the northwest corner of the island. The flare tower would have both low pressure and high pressure flare tips. The flare would combust natural gas releases that may result during oil processing (e. g., safety purges of equipment) and from equipment being started-up/shutdown due to maintenance. The smokeless flare will meet State of Alaska opacity requirements, and API 520/521 guidelines would be used for vent system and flare design. The low pressure flare will operate continuously through pilot and feed gas to the system. The flame would be smokeless and yellow to light orange in color. Low luminosity would be expected because the flame should be virtually transparent. The high pressure flare would operate only as required, and for short periods. Flaring would not be expected more than 30 days per year. Pilot and purge gas would be provided continuously to the flare tip. While flaring, the flame would be smokeless, virtually transparent, and light yellow and blue in color.

Offshore Pipeline Construction: Pipeline segments would be transported by truck to an approximately 5,000 by 750 ft (1,524 by 228.6 m) staging area prepared on the bottom-fast ice adjacent to the pipeline corridor. Pipeline segments would be welded into 5,000-ft (1,524 m) sections (pipeline strings) at the staging area.

A slot would be cut in the ice along the pipeline route using ice trenchers and large trenching equipment (ditch witches). Blocks of ice would be removed by backhoes, and front end loaders would move the ice away from the work site (Figure 4-20). A trench to allow a 6 ft (1.8 m) depth of cover over the pipeline, and 8 ft (2.4 m) wide at the bottom, would be excavated in the nearshore zone between the shoreline and the barrier islands (Figure 4-21). A trench to allow for 7 to 9 ft (2.1 to 2.7 m) depth of cover over the pipeline, and approximately 10 to 12 ft (3 to 3.7 m) wide at the bottom, would be excavated in deeper, offshore water north of the barrier islands to Seal Island (Figure 4-22). The bottom of the trench would be cut to the desired final

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grade by use of a hydraulic excavator, which discharges the excavated spoils back into the trench (Figure 4-23). Tracked equipment would tow pipeline strings to the side of the trench, where tie-in welds to the previously laid strings would be made and non-destructive testing performed on welds. Tracked equipment on one side of the ice slot would control the position of the pipelines while they are lowered through the opening into the seafloor trench. Backfilling would be performed concurrently with pipe laying activities. Pipelines would be pressure tested with a glycol/water mix prior to use.

Excess trench spoils associated with offshore pipeline installation would be disposed of immediately north of the barrier islands in water depths greater than 5 ft (1.5 m) in a 1,200- by 2,700-ft (365.8 by 823 m) area. The volume of trench spoils disposed of in this area may increase if adverse weather or ice conditions dictate the abandonment of operations prior to completion of pipeline installation activities. Material stored in this disposal area would be leveled to an average height of 1-ft (0.3 m) in any 100- by 100-ft (30.5 by 30.5 m) area. Maximum height of individual features would not exceed 2 ft (0.6 m). Some residual trenched material, less than 3 ft (0.9 m) deep may also be disposed in an area along the west side of the offshore trench where water depths are greater than 5 ft (1.5 m).

Onshore Pipeline Construction: Construction of the onshore pipelines would be accomplished using equipment and methods which have been used in the Arctic region for many years. Typical onshore pipeline construction activities are discussed below and shown on Figure 4-12.

<u>VSM and Pipeline Installation</u>: The pipe laying process would commence in January by surveyors staking positions where VSMs would be installed. VSM holes would be drilled and the tailings cleared. The average spacing for VSMs is approximately 55 ft (16.7 m). The tailings from VSM installation would be disposed of at the Put 23 mine site or the newly opened Kuparuk River Delta Northstar mine site. VSMs would be strung along the pipeline alignment together with the support beams. The VSM assemblies would be set in holes approximately 6 ft (1.8 m) deep, which are typically filled with sand slurry or foam.

Upon completion of VSM installation on a segment of the pipeline, joints of line pipe would be transported to the site, strung along the pipeline alignment, and welded together to form a continuous string. Each weld produced in the field would be examined by non-destructive testing methods. The pipeline strings would then be lifted onto the VSMs, and tie-in welds performed and examined. Applying insulation to the tie-in welds would conclude the pipe-laying activities. The horizontal bar which supports the oil and gas pipeline across the top of the VSMs would be a minimum of 5 ft (1.5 m) above the ground to allow passage of caribou beneath the onshore pipeline alignment.

Completed segments of the pipelines would be hydrotested with a glycol/water mix after they are installed to satisfy applicable regulations and codes. The test fluid would be pumped into the pipeline and the pressure would be increased until the desired test pressure (1.25 times the maximum allowable operating pressure) has been reached. This pressure would be maintained for a minimum of 8 hours. The pressure would then be gradually reduced to atmospheric pressure and the fluid transferred to another segment of the pipeline. These activities would require approximately 10 days to complete (in mid-April). To reduce the volume of fluid required, the pipelines would be tested one after the other by transferring the testing fluid from one to another. Hydrostatic test fluids would either be stored for future work, injected into an approved disposal well, or sent back to the supplier for recycling.

Putuligayuk River Crossing: The Putuligayuk River crossing would be an aboveground crossing that spans the river. VSMs would be used to support the oil pipeline across the span. The support(s) would be installed from the surface of the ice by drilling a hole through the ice and the underlying soil until the required pile length is achieved. The VSMs would be designed to resist the impact forces of ice at breakup.

Valve Stations: The pipelines would have automated quick closure valves located at Seal Island. A remotely controlled shut-down valve would be located at the end of the oil pipeline at Pump Station No. 1. A manually operated isolation valve would also be placed on each side of the Putuligayuk River crossing. They would be installed in line and would be situated close to supporting VSMs on either side of the river. These valves would be protected from cold weather conditions by standard North Slope insulating jackets and not enclosed in buildings. The use of gravel pads for these valves is not expected to be required. Access to the Putuligayuk River valves would be from the service road via existing catwalks located between the road and the oil pipeline.

The pipelines would also be provided with automated, quick closure valves at the shore approach where the pipelines transition from buried subsea pipelines to aboveground onshore pipelines. At this location, an onshore gravel valve pad would be constructed to support the transition from buried to aboveground pipeline segments. The valve pad would be set back approximately 110 ft (33.5 m) from the shoreline bluff to help protect it from coastal erosion and potential storm surge and ice override events (Figure 4-24). A gravel berm will be constructed around the north and west sides of the pad in the vicinity of the valve enclosure, gas-fired generator, and controls building to help further protect these facilities from potential ice override events. This construction activity would include an 8-ft (2.4 m) wide trench through the transition zone to the 70- by 135-ft (21.3 by 41 m) gravel pad (Figure 4-25).

The trench in this transition area would be backfilled with select material and the onshore portion would be finished with a layer of soil and revegetated. Excess material obtained from excavation of the shore approach trench would be transported to the Put 23 mine site or the proposed new mine site in the Kuparuk River for disposal. A permanent access road to the gravel pad is not planned; the pad would be sized to accommodate a helipad for year-round access.

The gas-fired generator would receive its fuel from a tap off the gas line going to Seal Island. The generator would charge a battery bank which would power all instrumentation for leak detection and monitoring, communications, and automated valve status and control. The battery bank is sized to provide 15 days of power, should the generator be off-line. Power from the batteries would energize a solenoid valve which would keep the valve open. A loss of power at the shore crossing would cause the valves to close.

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Pig Launching/Receiving Facilities: Pig launching and receiving facilities would be provided for the oil and gas pipelines. At the island, these facilities would be incorporated within the process module and would be permanent. The pig launcher for the gas pipeline would be installed on a gravel pad approximately 170 ft (51.8 m) long and 85 ft (25.9 m) wide on the south side of the CCP facility (Figures 2.4-20 and 2.4-21, Appendix A). The pig launcher at Pump Station No. 1 would be adjacent to the facility and would not require construction of a new gravel pad.

Construction-Related Wastes/Discharges: Sanitary, domestic, and construction related wastes generated during winter construction activities (ice road construction, gravel hauling, and placement) would be collected and backhauled to existing waste injection and/or approved disposal facilities onshore. Wastes generated during island construction activities during the broken ice and/or open water seasons (island slope protection and facilities installation and hookup) would be consolidated and stored onsite until transportation to shore and disposal at an approved disposal facility could be safely accomplished. Treated domestic and sanitary wastewater may be discharged through Outfall 001 following its installation. Upon completion of the Class I industrial waste disposal well, such wastewater would be disposed of in the well.

Construction of the seawater intake structure and marine outfall lines at the island would require a dewatering discharge to the marine environment. This discharge results as seawater seeps through subsea gravels into a construction trench as the pipelines are installed from the subsea environment to the island's surface. These waters are pumped from the construction area back into the Alaskan Beaufort Sea. It is anticipated that this construction-related discharge would occur discontinuously during an approximate 2- to 4-week time frame during early spring (April to May). The expected flow rate for this discharge is 1 million gallons per day (gpd) (3.7 million liters per day [liters/day]), but could approach 2 million gpd (7.6 million liters/day). Other characteristics associated with this discharge are shown in Table 4-6. Additional information regarding this discharge is presented in a draft National Pollutant Discharge Elimination System Permit and Fact Sheet (Appendices F and G). For the Preliminary Final National Pollutant Discharge Elimination System Permit being proposed by the U.S. Environmental Protection Agency see Appendix O.

Construction Schedule: BPXA is considering both a single winter season and a two winter season program associated with island construction and onshore and offshore pipeline installation activities. BPXA's preferred program is to conduct these construction activities in two seasons, separating island construction from pipeline installation. This reduces logistical problems and work schedules can be accommodated more efficiently. However, a single season may be required as a result of permit scheduling and/or other factors external to the project. It should be noted that BPXA would not haul gravel for island construction or install pipelines during the summer open water season as part of either construction program.

A likely scenario for a single-season construction schedule is presented in Table 4-7. All major construction activities, including island construction, onshore and offshore pipeline installation, and island infrastructure and module installation and hookup would occur in one year. The exception to this would be the installation of road and caribou crossings which would occur prior to the start of island construction activities. For a single-season construction schedule, the drill rig would be transported via barge during September and set up

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on the island. Drilling would commence in late September using fuel gas provided by the gas pipeline. A barge would be used to transport a 4-month supply of drilling consumables during September to provide sufficient quantities until an ice road is again built the following January. With the exception of the gravel island and associated sheet pile wall and slope protection, which is scheduled to begin in March 1999, the applicant has elected a one year construction hiatus to the present schedule based on a business decision driven by low oil prices and the need to reduce capital expenditures in 1999.

A likely scenario for a two-season construction schedule is presented in Table 4-8. Under this scenario, all work associated with the road and caribou crossings and construction of the island would occur within the first season. Based on the decision by the applicant to delay, installation of the onshore and offshore pipelines, facilities installation, and drilling would occur during the following years. For both schedules, the initial phase of development drilling would be completed approximately 21 months later.

4.4.2.3 Proposed Drilling Activities

Well Drilling Program: Seal Island facilities would be designed to accommodate a maximum of 37 wells. Initially, 23 wells would be drilled: 15 oil producers, 7 gas injectors, and 1 Class I industrial waste disposal well. The additional 14 well slots could be used for infill drilling and an additional waste injection well, if necessary.

The drilling rig anticipated for use is the Nabors 33E rig. This rig can be broken down into light loads and trucked over floating ice roads, or mobilized by barge. The drilling rig would provide its own power using generators fired by fuel gas imported to the island via the gas pipeline. This source would be used until the processing facilities become operational, and fuel gas would be supplied to the drilling rig by island processing facilities. Once drilling activities commence, they would continue for approximately 2 to 2.5 years until all planned wells were drilled and completed.

Since freshwater would not be available in sufficient quantities, drilling muds and well completion brines would be formulated using seawater, which differs from current onshore North Slope drilling practices.

Well Control: There would be three types of development wells (oil producers, Class I industrial waste disposal, and gas injectors). All wells would have subsurface safety valves in the completion string and wellhead controls and valving consisting of:

- Master valve (manual).
- Surface safety valve (actuated).
- Wing valve (manual).
- Swab valve (manual).

The well cellars for all wells would be lined with an 8-ft (2.4 m) diameter culvert set in the gravel pad, then 6 inches (15.2 cm) of concrete would be poured in the base.

The Northstar reservoir pressures are very similar to those originally found in the Prudhoe Bay field. In the seven exploration and appraisal wells drilled to date into the structure, there have been no well control incidents or indications of shallow gas accumulations. However, for all development wells there would be a diverter installed for drilling all surface hole sections, and a blowout preventor stack would be utilized for drilling all intermediate and reservoir hole sections.

Drilling-Related Wastes/Discharges: Domestic, drilling, and/or sanitary wastes generated during drilling activities would be either stored on-site until permanent island disposal facilities are in operation, or backhauled to existing waste disposal facilities onshore. Once the Class I industrial waste disposal well has been drilled and completed, and a cuttings grind and inject unit installed on the island, drilling muds and cuttings would be disposed of via the Class I industrial waste disposal well. Under no circumstances would drilling muds and cuttings be discharged to the marine environment.

4.4.2.4 Proposed Operation/Maintenance Activities

Oil Recovery and Transport: Gas cycling is the preferred oil recovery method for depleting the Northstar reservoir because reservoir tests and modeling results suggest this method of oil and gas recovery will produce more oil than other recovery methods. Target locations for oil producers, gas injectors, and Class I industrial waste disposal wells to support the gas cycling program are shown on Figure 4-26. Approximately 100 million standard cubic feet (2.83 million m^3) per day of natural gas would be sent via a subsea pipeline from the CCP located onshore in the Prudhoe Bay Unit to Seal Island to assist with the gas cycling process. A simplified process flow diagram using gas cycling as the method for oil and gas recovery is presented on Figure 4-27. A production curve for gas cycling over the proposed 15-year life of the Northstar reservoir is presented on Figure 4-28.

Approximately 700 to 800 tanker trips per year leaving the Valdez marine terminal are required to accommodate current North Slope production (USDOI, MMS, 1996:IV.4-30). Production of recoverable reserves from the Northstar reservoir could require the operation of additional tankers from the Valdez marine terminal. It is estimated that 198 tankers would be required over the life of the project to accommodate Northstar reservoir production (the average capacity of tankers calling at the Valdez Marine Terminal is approximately 800,000 barrels) (Table 4-9). At peak production, tanker trip requirements would increase over current levels. Thirty tanker trips per year during peak production years 2,3, and 4 would be required, a 4.3% increase over current levels. After production has peaked, additional tanker movements decrease to one by the 14th year of production. These estimates do not include North Slope decreases in field production or possible increases in production from additional developments. However, decreases in oil production overall may offset the need for increased tanker trips that would result from Northstar production.

Island Surface Management: The island surface would be regraded to the design contours on an annual basis following spring breakup. Once barge access to the island is available, earthmoving equipment would be mobilized to the island to blade and compact the surface, and the existing gravel would be reshaped to comply with the grading plan. Should additional material be required, it would be mined at the Put 23 mine site,

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hauled to West Dock, then transported via barge to the island. Some surface subsidence is expected during the first few years. The majority of subsidence is expected near the wellheads (1 to 2 ft [0.3 to 0.6 m]) immediately next to well cellars, and would pose no safety problems. Localized subsidence around the island surface should be less than 6 inches (15 cm) and would be corrected by regrading. If necessary, the island would again be graded just prior to freezeup each year.

Island Operation/Maintenance - Bench Maintenance and Repair: The entire slope-protection system would be inspected annually, both above and below waterline, during the open water season to document the condition of the armor. The inspection would involve visual observation of the concrete mats and linkage hardware. The annual inspection would also include profiling of the bench and below water slopes to detect changes in configuration.

During initial block production for construction, maintenance replacement blocks would be produced. These blocks would be stockpiled in Deadhorse and would be available for immediate repairs identified by the inspection team. Filter fabric also would be stockpiled in Deadhorse.

The frequency of repairs to the Seal Island slope-protection system would depend on the severity of the wave and ice conditions to which it is subjected. When repairs are required, a tracked crane would be mobilized to the island, along with a small crew of divers and equipment operators. The repair work would be conducted from the bench on the outside of the sheet-pile wall. The crane would work from wood crane mats to avoid damage to the bench surface concrete mats. Divers would map the damaged area and detach the linkages of the blocks as required. If necessary, the damaged area would be regraded and filter fabric would be installed by crane. Replacement mats would be made up on the bench surface and lowered via crane to replace the damaged section. The damaged blocks would be transported to shore for disposal.

The sacrificial gravel berm at the toe of the slope has been designed to reduce damage to the concrete mat due to wave and ice impacts. This berm would not be slope-protected and, therefore, would be subject to erosion and relocation during major storm and/or ice events. Previous surveys of eroded gravel islands in the Alaskan Beaufort Sea (e.g, Seal Island, Mukluk Island) indicated a predominant migration of eroded gravel from the east to the west, in response to the prevailing northeasterly winds and waves during the open water season. It is anticipated that the direction of gravel transport would reverse direction under the influence of major, yet less frequent, westerly storms. It is expected that the northeast corner of the island (where the surface width of the berm is 100 ft [30.5 m]) would erode, with the resulting gravel loss moving to the west and south. It is not possible to predict the frequency of gravel berm replenishment. Should major storm events occur, gravel berm replenishment could be necessary on an annual basis.

The repair gravel may be delivered from an onshore mine site in either winter (via ice road) or in summer (via barge). Under these circumstances, gravel placement would require bulldozing the gravel through a slot in the wintertime ice sheet, or clamming or bulldozing the gravel off a barge during summer.

If berm erosion and gravel displacement is minor, berm replenishment may be accomplished by "backpassing," or relocating the gravel from areas of deposition back to eroded areas. A clamshell operation would be required to retrieve the gravel. The work platform for the clamshell would either be the 100-ft (30.5 m) wide island bench during winter or summer, or a floating barge in summer. Because this method of replacement would not require new gravel deliveries to the island, it would be the preferred choice for berm maintenance.

Snow Removal: During the winter months, snow removal activities would be conducted on an ongoing basis. Snow would be cleared to maintain a safe operating surface and to prevent snow from contacting any contamination sources. Equipment and personnel on the island would be adequate to handle the continual snow removal requirements. All snow would be visually inspected for contamination before removal. Snow dumping would occur around the entire perimeter, wherever access is available. It is likely that access would be most available on the south side of the island. Uncontaminated snow would be dumped off the edge of the island onto the bench or onto the sea ice, where it would be allowed to melt and run off into the ocean during breakup. Any snow found to contain contamination would be melted and injected in the Class I industrial waste disposal well.

Electrical Power: Once production facilities are operational, base-load power requirements would be approximately 18 megawatts, and be provided by multiple, gas-fired turbine generators. Emergency power would be provided by two 2,600-kilowatt diesel generators installed during the construction phase.

Instrumentation and Controls: Instrumentation and controls would follow current industry practices for remote facilities and include:

- Local and remote monitoring of well, process, and safety data.
- Pipeline leak detection.
- Automatic alarms that report operating conditions outside of programmed parameters.
- Security systems to prevent unauthorized modifications.
- Remote terminal units for pipeline monitoring and transmitting data.
- Standardized instrumentation for modules and equipment.
- Unit shutdown and emergency shutdown system capabilities.

Operator consoles would be located in a central control room. The operating system would display process conditions and equipment status, including alarms, trip conditions, and fire/gas detection status. Alarms would be relayed to the operator on a real-time basis, allowing the operator to make rounds through the plant. Emergency shutdown devices could be activated either manually or remotely via the Supervisory Control and Data Acquisition (SCADA) System.

Operations-Related Wastes/Discharges: Operation of Seal Island facilities associated with the development/ production of the Northstar Unit would require several marine discharges. These proposed operational discharges are summarized below by outfall identifier, and include:

- Outfall 001(a) - Continuous flush system.

- Outfall 001(b) - Brine effluent associated with the potable water system.

· Outfall 001(c) - Effluent from the domestic/sanitary wastewater treatment system (temporary marine discharge during periods when the Class I industrial waste disposal well is not available).

· Outfall 002 - Seawater discharged through fire suppression system during annual tests.

The source of water feeding these operational outfalls would be seawater collected through a seawater intake system. Seawater from the intake system would be utilized by various facility operations. The seawater intake system is anticipated to take in an average 40,500 gpd (153,309 liters/day), which would be diverted to the potable water system, continuous flush system, and the drilling muds and cuttings grind and inject equipment. Seawater used for annual testing of the fire suppression system would also be provided through this intake system. Figure 4-29 illustrates the flow of seawater collected by this intake system through various facility systems terminating with Outfalls 001(a-c) and 002 and the Class I industrial waste disposal well. As shown on Figure 4-29, dechlorinators would be used to ensure marine discharges satisfy Alaska Water Quality Standards. Figure 4-30 presents a cross-section of Outfalls 001(a-c) at Seal Island.

Outfall 001 would consist of up to three commingled streams: continuous flush (Outfall 001a), brine effluent (Outfall 001b), and treated domestic/sanitary wastewater effluent (Outfall 001c). The continuous flush system would be designed to prevent ice formation and biofouling. The desalination brine would be a byproduct of the potable water system that renders freshwater from seawater. The freshwater produced would be utilized for both human and operational activities. Domestic/sanitary wastewater, following an activated sludge and ultraviolet treatment, would generally be discharged through the Class I industrial waste disposal well, but may occasionally be discharged via Outfall 001. This domestic/sanitary wastewater stream would result almost exclusively from human activities, such as food preparation, consumption, and bathing, and would not contain any fluids related to the oil production/processing systems. As noted above, collectively these three streams are referred to as Outfall 001. This outfall would have an average flow rate of 27,928 gpd (105,719 liters/day), with a maximum flow rate of 49,020 gpd (185,560 liters/day).

The fire water test discharge (Outfall 002) would be an annual discharge required for testing the island's principal fire suppression system. During a test, seawater would be pumped through selected monitors to ensure adequate pressure and supply is available in the event of fire or explosion. This outfall is expected to discharge up to 88,200 gallons (333,872 liters) annually during its 30-minute test duration.

Table 4-6 provides additional details for the above outfalls, including: flowrates, temperatures, pH, salinity, biological oxygen demand, total suspended solids, total residual chlorine, turbidity, sediments, toxics, and fecal coliforms.

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Pipeline Leak Detection: Daily operation of the pipeline would be monitored on a continuous basis by the SCADA system, which provides operating personnel with real-time information on pipeline status. In order to help ensure the proper operation of the system, regular checks would be conducted on the equipment employed, including the hardware and associated software.

In addition to the valves discussed above, the equipment involved in the leak detection system would include the following:

- Flow meters installed at the inlet and outlet of the pipelines.

- Pressure and temperature indicators at each flow meter location (to improve the response time of the system, an additional set of pressure and temperature indicators will be installed at the shore approach location).

- A communication link with the SCADA system, capable of updating the information as required by the leak detection system.

Information on pipeline condition, both with regard to vertical and horizontal position in the trench, and condition of the wall thickness would be obtained by means of pigging devices that would be run at predetermined intervals. After reviewing the results from these inspection runs, the necessary preventative and/or corrective actions would be identified and implemented, if required.

Visual inspection would be performed to detect chronic leaks below the threshold of the leak detection system. Weekly aerial surveillance would be performed during the summer over the offshore and onshore pipeline routes to visually detect oil spills. In the winter, ice cover would hamper aerial surveys of the offshore pipeline by hiding the oil from view. A through-the-ice surveillance program of the offshore pipeline would be performed every 30 days in the winter during solid ice conditions. Holes would be drilled through the ice at regular intervals along the pipeline route to search for evidence of hydrocarbons that could have entered the marine environment through a pipeline leak. The effectiveness of this oil spill detection technique is discussed in Section 8.5.1.

Pigging: Pigging would be performed to measure wall thickness; determine pipeline geometry; assess any mechanical damage; clean and remove any paraffin, scale, and sediment buildup; and distribute any pipeline corrosion inhibitor, if necessary. Table 4-10 provides details of the proposed pig runs.

For the purpose of performing the pigging activities, the oil pipeline would have pig launching facilities at Seal Island and receiving facilities at Pump Station No. 1. The gas pipeline would have a pig launcher installed onshore at the gas supply point, and the pig receiver would be located on Seal Island. Transportation of the pigs and the necessary supplies to and from the island would be part of the routine island supply.

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Pipeline Repair: Repairs to the onshore facilities would be accomplished from existing roads running along the alignment of the pipelines, by using all-terrain vehicles, or from winter ice roads built specifically to access a location. Access also would be achieved by employing a helicopter to move personnel and equipment. Typically, minor repairs would require only hand tools and, possibly, welding equipment. Major repairs might require the use of earth-moving equipment, cranes and lifting equipment, and specialized tools and materials. Equipment, materials, and personnel to conduct minor and major pipeline repairs are generally available in the Deadhorse service area on a year-round basis.

Spare parts and replacement materials would be maintained at both Seal Island and onshore to provide quick response to minor emergencies and perform repairs to pipeline flow and leak detection facilities. These repairs would be performed by personnel employed as part of routine facility operations. Personnel from the production island could be mobilized by helicopter to the valve pad if required.

The complexity of repairs to the offshore pipelines increases with water depth. Pipeline damage caused by internal or external corrosion or external forces would require pipeline excavation. Damaged pipeline sections would either be replaced, or repaired using an external pipeline shrink sleeve. Regardless of the season, underwater divers and excavation, welding, and pressure testing equipment would be required for offshore pipeline repairs. Specialist contractors and equipment may be needed to perform activities such as blocking flow inside a pipeline by creating an internal ice plug. Repair operations would be carried out from a locally- available barge in the summer. Winter repair activities would be performed from the ice surface using techniques and equipment similar to those used during construction. Performance of repairs may be difficult or impossible during freezeup or breakup periods due to the unsafe conditions for personnel. In this situation, the damaged pipeline would be closed by isolation valves until repairs could be made.

4.4.2.5 Manpower Requirements

Estimated average monthly manpower requirements to support a single season construction program would peak at approximately 375 personnel. Estimated average monthly manpower requirements to support a two season construction program would peak at approximately 285 personnel. The distribution of personnel by month are broken down by specific work activity for each of these two construction scenarios in Tables 4-11 and 4-12.

An operational workforce of approximately 100 would be employed at the Seal Island facilities and onshore facilities following completion of drilling and through the 15-year life of operation.

4.4.2.6 Transportation Requirements

The method (bus, barge, boat, helicopter, and truck) and estimated number of trips required to support construction, drilling, and operations/maintenance activities for both a single season and a two season construction program are summarized below and presented in more detail in Tables 4-13 and 4-14, respectively.

Table 4-11 (page 1 of 1)

Table 4-12 (page 1 of 1)

Table 4-13 (page 1 of 2)

Table 4-13 (page 2 of 2)

Table 4-14 (page 1 of 2)

Table 4-14 (page 2 of 2)

As shown on these tables, the primary differences between the single season and two season construction requirements for this alternative are associated with differences between bus, barge, helicopter, and truck requirements. The single season construction schedule will require 150 fewer bus trips, 4 fewer barge trips, and 240 more helicopter trips than the two season construction schedule for process facilities installation between August and November. In addition, the single season construction schedule will require 7 more barge trips and 80 fewer truck trips to support the drilling program than the two season construction schedule.

4.4.2.7 Development/Production Facilities Abandonment/Reuse Potential

BPXA would be required to develop a Northstar Unit development/production facilities Abandonment Plan when the reservoir is depleted. An abandonment plan would require approval by the U.S. Army Engineer District, Alaska, MMS, and ADNR before implementation. The plan would include an assessment of the environmental consequences of the abandonment activities.

Abandonment activities would take several months to complete and could involve a range of scenarios. Two likely scenarios are: 1) removal of all facilities associated with Northstar Unit development, including Seal Island slope protection, island infrastructure, and onshore and offshore pipelines; and 2) abandonment of all island infrastructure, onshore pipeline removal, and offshore pipelines removed or abandoned in place, leaving Seal Island in place for possible reuse.

Requirements for Abandonment of Facilities: The Northstar reservoir is anticipated to produce oil in economic quantities for approximately 15 years after production commences. Once production ceases and facilities are no longer needed, oil and gas facilities would be abandoned in accordance with the approved abandonment plan, terms of individual lease agreements, terms of the Northstar Unit Agreement, and applicable state and federal statutes and regulations.

Abandonment With the Removal of All Development/Production Facilities: Abandonment with the removal of all development/production facilities would include the removal of Seal Island armor protection, all island infrastructure, and the abandonment of the onshore and offshore pipelines. Under this scenario, all production, injection, and Class I industrial waste disposal wells would be plugged and abandoned in accordance with state and federal requirements.

The development/production infrastructure located on the island would be dismantled, removed, and transported from the island over ice roads during winter months. Larger, heavier components, such as the process and compressor modules, may have to be transported from the island by barge during the open water season. These facilities would be reused at other development/production locations, stored for possible future use, salvaged as scrap material, or removed for disposal.

Buried offshore pipelines would be emptied and removed or abandoned in place. Abandoning pipelines in place would require removing all hydrocarbons and filling pipelines with seawater. Pipelines would not require excavation; eventually, buried pipelines would decay and become a component of the marine sediment. The onshore gravel valve station pad would be dismantled and removed for disposal. Gravel would be removed to the extent feasible and stored for reuse or transported back to an active gravel mine. The disturbed area would be rehabilitated and revegetated. VSMs that support onshore pipelines would be cut off below the land surface and removed. Onshore pipelines would be cut into pieces and reused to the extent feasible, salvaged as scrap material, or removed for disposal. This activity would take place during winter months and would require construction of ice roads to access the onshore gravel valve pad and onshore pipeline alignments.

The linked concrete armor around Seal Island would be dismantled, removed, and transported onshore by barge for disposal. This activity would take place during the open water season. The gravel island would be left unprotected and exposed to wave and ice erosion; with time, Seal Island would erode below the sea surface, similar to the current status of Northstar Island shoal (Section 4.2.2.1).

Abandonment of Development/Production Facilities With Seal Island Remaining: Abandonment with Seal Island remaining would require the removal of all development/production infrastructure, including onshore and offshore pipelines. Seal Island and the protective linked concrete armor around it would remain. Under this scenario, all production, injection, and waste injection wells would be plugged and abandoned in accordance with state and federal requirements.

The development/production infrastructure on the island would be dismantled, removed, and transported from the island over ice roads during winter months. Larger, heavier components, such as the process and compressor modules, may have to be transported from the island via barge during the open water season. These facilities would be reused at other development/production locations, stored for possible future use, salvaged as scrap material, or removed for disposal.

Seal Island would remain in place as it has been designed. The island would require routine inspection and maintenance and may require periodic repairs as a result of continued exposure to wave and ice forces.

The onshore gravel valve station pad would be dismantled and removed for disposal. Gravel would be removed to the extent feasible, stored for reuse elsewhere, or transported back to an active gravel mine. The disturbed area would be rehabilitated and revegetated. VSMs that support onshore pipelines would be cut off below the land surface and removed. Onshore pipelines would be cut into pieces and reused to the extent feasible, salvaged as scrap material, or removed for disposal. This activity would take place during winter months and would require construction of ice roads to access the onshore gravel valve pad and onshore pipeline alignments.

Facility Reuse Potential: Alternative uses have been considered for this project in relation to abandonment and/or reuse of Northstar Unit development/production facilities after production has ceased. If maintained properly, Seal Island and its buried subsea pipelines could be used for future offshore oil and gas development (such as the Sandpiper Unit discussed in Chapter 10). This would eliminate the need for additional pipelines to existing onshore facilities.

Seal Island also could be utilized by non-oil and gas industries once the leases are relinquished to the state. Seal Island could serve as a staging camp for local NSB residents to assist with subsistence hunting activities (e.g., seals and bowhead whales). Seal Island could also serve as a base for Alaskan Beaufort Sea research facilities or become part of the expanding North Slope tourism industry.

4.4.3 Alternative 3 - Point Storkersen Landfall to West Dock Staging Pad

4.4.3.1 Overview of Alternative

The principal difference between Alternative 3 and Alternative 2 (previously described in detail in Section 4.4.2) is a variation in the onshore oil and gas pipeline alignment and valve pad location. The oil and gas pipelines associated with Alternative 3 follow the same offshore corridor from Seal Island to Point Storkersen as Alternative 2. The buried subsea pipelines would transition to aboveground pipelines in a similar manner and location as that described for Alternative 2. A small gravel pad, approximately 50 by 50 ft (15.2 by 15.2 m) in size, surrounded by a protective gravel berm, would be constructed to accommodate pipeline transition from subsea to aboveground at Point Storkersen. However, once onshore, the oil and gas pipeline corridor would turn east until it intersected the existing pipeline corridor between PM1 and the West Dock Staging Pad. A check valve would be placed in the oil line at the shore crossing, and a small gravel valve pad approximately 75 by 75 ft (23 by 23 m) in size would be constructed adjacent to the point of intersection with the existing pipeline corridor between PM1 and the West Dock Staging Pad. Valves and instrumentation at this pad would be powered by electricity from the existing onshore power grid.

From that intersection, the oil and gas pipelines parallel the existing pipeline corridor to the West Dock Staging Pad, where they turn south following an existing pipeline and roadway corridor to the CCP, where the gas pipeline terminates. The oil pipeline continues from the CCP to Pump Station No. 1 via a combination of existing and new pipeline and/or roadway corridors.

A more detailed description of pipeline alignment information for this alternative is presented in Table 4-15. The offshore and onshore pipeline alignment for this alternative is shown on Figure 4-31.

Onshore oil and gas pipeline alignments locations and lengths differ with this Alternative than that described for Alternative 2. The onshore pipeline alignments would also require that onshore ice road lengths and locations differ from those presented for Alternative 2 (they would parallel the new pipeline alignments). The amount of freshwater needed for ice road construction differs from Alternative 2 (see footnote in Table 4-15). Since the onshore pipelines are longer, construction manpower and related equipment needs would increase over those presented for Alternative 2 in order to complete these construction activities within the 5-month (January through May) time frame as shown. These requirements are presented below. Because the offshore structure, gravel mine site, pipeline construction methods, and operations/maintenance and abandonment activities would be the same as Alternative 2, these will not be described again.

Figure 4-31 (page 1 of 2)

Figure 4-31 (page 2 of 2)

Table 4-15 (page 1 of 1)

4.4.3.2 Manpower Requirements

Estimated average monthly manpower requirements to support a single season construction program would peak at approximately 410 personnel. Estimated average monthly manpower requirements to support a two season construction program also would peak at approximately 410 personnel. The distribution of personnel by month are broken down by specific work activity for each of these construction season scenarios on Tables 4-16 and 4-17.

An operational workforce of approximately 100 would be employed at the Seal Island facilities and onshore facilities following completion of drilling and through the 15-year life of the operation.

4.4.3.3 Transportation Requirements

The method (bus, barge, boat, helicopter and truck) and estimated number of trips required to support construction, drilling and operations/maintenance activities for both a single season and a two season construction program are summarized below and presented in more detail in Tables 4-18 and 4-19, respectively.

As shown on these tables, the primary differences between the single season and two season construction requirements for this alternative are associated with differences between bus, barge, truck, and helicopter requirements. The single season construction schedule will require 150 fewer bus trips, 4 fewer barge trips, and 240 more helicopter trips than the two season construction schedule for process facilities installation between August and November. In addition, the single season construction schedule will require 7 more barge trips and 80 fewer truck trips to support the drilling program than the two season construction schedule.

4.4.4 Alternative 4 - Point McIntyre Landfall to West Dock Staging Pad

4.4.4.1 Overview of Alternative

The principal differences between Alternative 4 and Alternatives 2 and 3 (previously discussed in Sections 4.4.2 and 4.4.3, respectively) is a variation in the landfall location and the corresponding onshore and offshore pipeline corridor alignments. The oil and gas pipelines associated with Alternative 4 follow the same offshore corridor from Seal Island toward Point Storkersen as does Alternative 2 until it reached the southern boundary
of the Northstar Unit. The offshore corridor then would turn southeast toward West Dock, staying north of Stump Island in water depths between 5 and 12 ft (1.5 and 3.7 m). As the corridor approached West Dock at the east end of Stump Island, it would turn in a southwest direction, making landfall approximately midway between PM1 and the West Dock Staging Pad. A gravel valve pad approximately 75 by 75 ft (23 by 23 m) in size would be constructed at this landfall location to accommodate the buried subsea pipeline transition to aboveground. This transition would be conducted in a manner similar to that previously described for Alternatives 2 and 3. The valves and instrumentation on this pad would be powered by the existing onshore power grid. The oil and gas pipelines then would parallel the existing

pipeline corridor to the West Dock

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Staging Pad. From the West Dock Staging Pad, the pipelines would be routed to the CCP and on to Pump Station No. 1, the same as described for Alternative 3.

More detailed pipeline corridor information for this alternative is presented in Table 4-20. The offshore and onshore pipeline alignment for this alternative is shown on Figure 4-32.

As discussed above, onshore and offshore oil and gas pipeline alignments and landfall and valve pad location differ with this alternative from those described for Alternatives 2 and 3. The onshore and offshore pipeline alignments would also require that ice road lengths and locations differ from those presented for Alternatives 2 and 3 (they would parallel the new onshore and offshore pipeline alignments). The amount of freshwater needed for ice road construction differs from Alternatives 2 and 3 (see footnote in Table 4-20). In addition, offshore pipeline staging areas would be relocated along the offshore pipeline alignment.

Since the offshore and onshore pipeline alignments are different, construction manpower and related equipment needs would differ from those presented for Alternatives 2 and 3. These requirements are presented below. Because the offshore structure, gravel mine site, pipeline construction methods, and operation/maintenance and abandonment activities would be the same as Alternatives 2 and 3, these will not be described again.

4.4.4.2 Manpower Requirements

Estimated average monthly manpower requirements to support a single season construction program would peak at approximately 420 personnel. Estimated average monthly manpower requirements to support a two season construction program would peak at approximately 330 personnel. The distribution of personnel by month are broken down by specific work activity for each of these construction season scenarios in Tables 4-21 and 4-22.

An operational workforce of approximately 100 would be employed at the Seal Island facilities and onshore facilities following completion of drilling and through the 15-year life of the operation.

4.4.4.3 Transportation Requirements

The method (bus, barge, boat, helicopter and truck) and estimated number of trips required to support construction, drilling and operations/maintenance activities for both a single season and a two season construction program are summarized below and presented in more detail in Tables 4-23 and 4-24, respectively.

As shown on these tables, the primary differences between the single season and two season construction requirements for this alternative are associated with differences between bus, barge, truck, and helicopter requirements. The single season construction schedule will require 150 fewer bus trips, 4 fewer barge trips, and 240 more helicopter trips than the two season construction schedule for process facilities installation

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between August and November. In addition, the single season construction schedule will require 7 more barge trips and 80 fewer truck trips to support the drilling program than the two season construction schedule.

4.4.5 Alternative 5 - West Dock Landfall

4.4.5.1 Overview of Alternative

The principal differences between Alternative 5 and Alternatives 2, 3, and 4 (previously described in Sections 4.4.2, 4.4.3, and 4.4.4, respectively) is another variation in the landfall location, with resulting changes in the onshore and offshore pipeline alignments. The oil and gas pipelines associated with Alternative 5 would follow the same offshore corridor from Seal Island south toward Point Storkersen as Alternatives 2 through 4, until it reached the southern boundary of the Northstar Unit. The offshore corridor would then turn southeast toward West Dock following the same corridor as Alternative 4, staying north of Stump Island in water depths greater than 5 ft (1.5 m). At the east end of Stump Island, the corridor would continue eastward until it intersected the West Dock causeway. The oil and gas pipelines would then transition from buried subsea to aboveground approximately 40 to 50 ft (12.1 to 15.2 m) from the edge of the causeway, then parallel the causeway to the West Dock Staging Pad. From the West Dock Staging Pad, the pipelines would be routed to the CCP and on to Pump Station No. 1 as described for Alternative 3.

Another aspect of this alternative that is different from other alternatives is that approximately 290,000 to 300,000 yd^3 (221,700 to 229,400 m^3) of gravel fill material would be placed along the west side of West Dock causeway to widen it by approximately 50 ft (15.2 m) between Dock Head 2 and the West Dock Staging Pad, a distance of approximately 0.9 miles (1.5 km). This fill would accommodate a valve pad area approximately 75 by 75 ft (23 by 23 m) in size, and VSMs for the oil and gas pipelines. Alternate landfalls on West Dock would result in larger or smaller volumes of gravel required for widening the causeway.

This additional width is necessary because:

- Extending the existing VSMs to the west would interfere with access to the existing buried water pipelines along the west side of West Dock.

- Stacking the pipelines vertically on the existing VSMs would interfere with maintenance access to the existing pipeline.

- Installing new VSMs along the west side of the buried water pipelines would prevent access to the water lines unless the new VSMs are installed to the west of the existing access road.

- The existing VSMs could be extended to the east, over the power cables which are presently buried between the VSMs and the roadway. This would increase the loading on the VSMs and limit maintenance access to the buried cables.

More detailed pipeline corridor information for this alternative is presented in Table 4-25. The offshore and onshore pipeline alignment for this alternative is shown on Figure 4-33.

As discussed above, onshore and offshore oil and gas pipeline alignments, landfall, and valve pad location differ with Alternative 5 from those described for Alternatives 2, 3, and 4. This landfall location does not require the 110-ft (33.5 m) setback from the shoreline, helipad, pipeline bedding backfill at the landfall, or revegetation of disturbed tundra. The valve pad at the landfall location would have power provided from the local onshore power grid.

The onshore and offshore pipeline alignments would require different ice road lengths and locations from Alternatives 2, 3, and 4 (they would parallel the new onshore and offshore pipeline alignments). The amount of freshwater needed for ice road construction differs from Alternatives 2, 3, and 4 (see footnote in Table 4-25). In addition, offshore pipeline staging areas would be relocated along the offshore pipeline alignments.

Since the onshore and offshore pipeline alignments are different, construction manpower and related equipment needs would differ from those presented for Alternatives 2, 3, and 4. These requirements are presented below. Because the offshore structure, gravel mine site, pipeline construction methods, and operation/ maintenance and abandonment activities would be the same as for Alternatives 2, 3, and 4, these will not be described again.

4.4.5.2 Manpower Requirements

Estimated average monthly manpower requirements to support a single season construction program would peak at approximately 420 personnel. Estimated average monthly manpower requirements to support a two season construction program would peak at approximately 330 personnel. The distribution of personnel by month are broken down by specific work activity for each of these construction season scenarios on Tables 4-26 and 4-27.

An operational workforce of approximately 100 would be employed at the Seal Island facilities and onshore facilities following completion of drilling and through the 15-year life of the operation.

4.4.5.3 Transportation Requirements

The method (bus, barge, boat, helicopter and truck) and estimated number of trips required to support construction, drilling and operations/maintenance activities for both a single season and a two season construction program are summarized below and presented in more detail in Tables 4-28 and 4-29, respectively.

As shown on these tables, the primary differences between the single season and two season construction requirements for this alternative are associated with differences between bus, barge, truck, and helicopter requirements. The single season construction schedule will require 150 fewer bus trips, 4 fewer barge trips, and 240 more helicopter trips than the two season construction schedule for process facilities installation between August and November. In addition, the single season construction schedule will require 7 more barge

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trips and 80 fewer truck trips to support the drilling program than the two season construction schedule. In addition, this alternative would require approximately 6,600 to 6,900 additional truck trips associated with gravel hauling for widening a portion of the West Dock causeway.

4.5 THE AGENCY PREFERRED ALTERNATIVE

As discussed in Chapter 1, one of the agency goals for this EIS is to support a consensus decision among the federal agencies and the NSB on the project that will go forward for development and production of the Northstar Unit. Because there are numerous components of the project, and many agencies with management and regulatory roles, there are many decisions to be made (Section 1.4). The components of the project under the jurisdiction of the lead and cooperating agencies are assessed in this chapter (Chapter 4) to develop the five alternatives described. As shown throughout this chapter, the differences in the action alternatives (2, 3, 4, and 5) are the route of the offshore pipeline, the landfall location, and the route of the onshore pipeline. Consensus was reached on specific alternatives to other project components (e.g., use of gravel island, island location, transportation by buried subsea pipeline) and on sets of alternatives from which the project developer can choose the appropriate action as further refinement is made to the project plan (e.g., gravel mined from the Kuparuk Delta site or the Kuparuk Deadarm site). For further discussion of agency preferred alternatives, see Section 11.9.1.

4.6 THE ENVIRONMENTALLY PREFERRED ALTERNATIVE

The environmentally preferred alternative has been identified by the lead and cooperating federal agencies, with the exception of the MMS, as Alternative 5 - West Dock Landfall. The MMS has identified Alternatives 2 and 3 (Section 11.9.2).

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