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BEAUFORT SEA BASIN PETROLEUM DEVELOPMENT SCENARIOS FOR THE FEDERAL OUTER CONTINENTAL SHELF

INTERIM REPORT

PREPARED FOR

BUREAU OF LAND MANAGEMENT

ALASKA OUTER CONTINENTAL SHELF OFFICE

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16. Abstract The Beaufort Sea Petroleum Development Scenarios Interim Report is the third of six reports comprising the first year of the Alaska OCS Socioeconomic Studies Program. The report postulates the discovery of oil and gas in any one of three offshore locations within the confines of the proposed federal OCS lease sale. Similarly postulated are five levels of discovered reserves, which when combined with three locations yields 15 scenario combinations. To these are assigned a large number of technical, developmental and operation assumptions which are drawn from the extensive technical/environmental background chapter that opens the report. Subsequently, the 15 scenarios are evaluated for their economic feasibility under differing economic assumptions; the result is a parametric analysis of required market prices to meet alternative financial objectives.

Four scenarios are then selected for more detailed analysis on the basis of broad geographical and reserve level representation, economic feasibility, and potential for physical and social impacts. The selected scenarios are elaborated with respect to: chronology of major phases and events, facility requirements and scheduling, manpower requirements and scheduling, production profiles, and locational factors affecting onshore facilities and pipeline routings.

The interim nature of the report refers to future analytical effects which will expand the scope of the scenarios to include the aggregation of all future petroleum-related activities on the North Slope of Alaska.

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Alaska, OCS Development, Beaufort Sea, Petroleum Development Scenarios

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NOTICES

1. This document is disseminated under the sponsorship of the U.S. Department of the Interior, Bureau of Land Management in the interest of information exchange. The U.S. Government assumes no liability for its content or use thereof.

2. This is an interim report designed to provide preliminary petroleum development data to the groups working on the Alaska OCS Socioeconomic Studies Program. The assumptions used to generate offshore petroleum development scenarios are subject to revision. A review of concerns and criticisms of some of the assumptions, and conditions under which alternative assumptions might provide a more accurate projection basis, is given in Appendix A. Specifically, the most significant concerns are the exploration activity assumptions found in Section 3.3 and Tables 3-4 through 3-9.

3. The units presented in this report are metric with American equivalents except for units used in standard petroleum practice. These are barrels (42 gallons, oil), cubic feet (gas), pipeline diameters (inches), well casing diameters (inches) and wel 1 spacing (acres).

4. Since this analysis was conducted two important petroleum-related events have occurred in Alaska. Jurisdiction of Naval Petroleum Reserve No. 4 (NPR-4) has been transferred from the Department of the Navy to the Department of the Interior becoming National Petroleum Reserve-Alaska (NPR-A) and the Alcan (Northwest) pipeline proposal has been selected to transport Prudhoe Bay gas to lower 48 markets.

ALASKA OCS SOCIOECONOMIC STUDIES PROGRAM
Beaufort Sea Basin Petroleum Development Scenarios for the Federal Outer Continental Shelf, Interim Report

Prepared by

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December 1977

FOREWARD

The United States Department of the Interior was designated by the Outer Continental Shelf (OCS) Lands Act of 1953 to carry out the majority of the Act's provisions for administering the mineral leasing and development of offshore areas of the United States under federal jurisdiction. Within the Department, the Bureau of Land Management (BLM) has the responsibility to meet requirements of the National Environmental Policy Act of 1969 (NEPA) as well as other legislation and regulations dealing with the effects of offshore development. In Alaska, unique cultural differences and climatic conditions create a need for developing additional socioeconomic and environmental information to improve OCS decision making at all governmental levels. In fulfillment of its federal responsibilities and with an awareness of these additional information needs, the BLM has initiated several investigative programs, one of which is the Alaska OCS Socioeconomic Studies Program.

The Alaska OCS Socioeconomic Studies Program is a multi-year research effort which attempts to predict and evaluate the effects of Alaska OCS Petroleum Development upon the physical, social, and economic environments within the state. The analysis addresses the differing effects among various geographic units: the State of Alaska as a whole, the several regions within which oil and gas development is likely to take place, and within these regions, the local communities.

The overall research method is multidisciplinary in nature and is based on the preparation of three research components. In the first research component, the internal nature, structure, and essential processes of these various geographic units and interactions among them are documented. In the second research component, alternative sets of assumptions regarding the location, nature and timing of future OCS petroleum development events and related activities are prepared. In the third research component, future oil and gas development events are translated into quantities and forces acting on the various geographic units. The predicted consequences of these events are evaluated in relation to present goals, values, and expectations.

In general, program products are sequentially arranged in accordance with BLM's proposed OCS lease sale schedule, so that information is timely to decision making. In addition to making reports available through the National Technical Information Service, the BLM is providing an information service through the Alaska OCS Office. Inquiries for information should be directed to: Program Director, Socioeconomic Studies Program, Alaska OCS Office, P. O. Box 1159, Anchorage, Alaska 99510.

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INTRODUCTION

PURPOSE

In order to aria” yze the socioeconomic and environmental impacts of Beaufort Sea pe roleum exploration, development and production, it is necessary to make reasonable predictions of the nature of that development. Petroleum development scenarios serve that purpose by providing a “project description” for the impact analysis.

Particularly important to socioeconomic studies are the manpower, equipment and material requirements, and the scheduling of petroleum development. The scenarios have to provide a reasonable range of technological, economic and geographic options so that both the minimum and maximum development impacts can be discerned. The primary purpose of this report is, therefore, to describe in detail a set of petroleum development scenarios that are the most economically and technically feasible based upon available estimates of oil and gas resources of the Beaufort Sea.

SCOPE

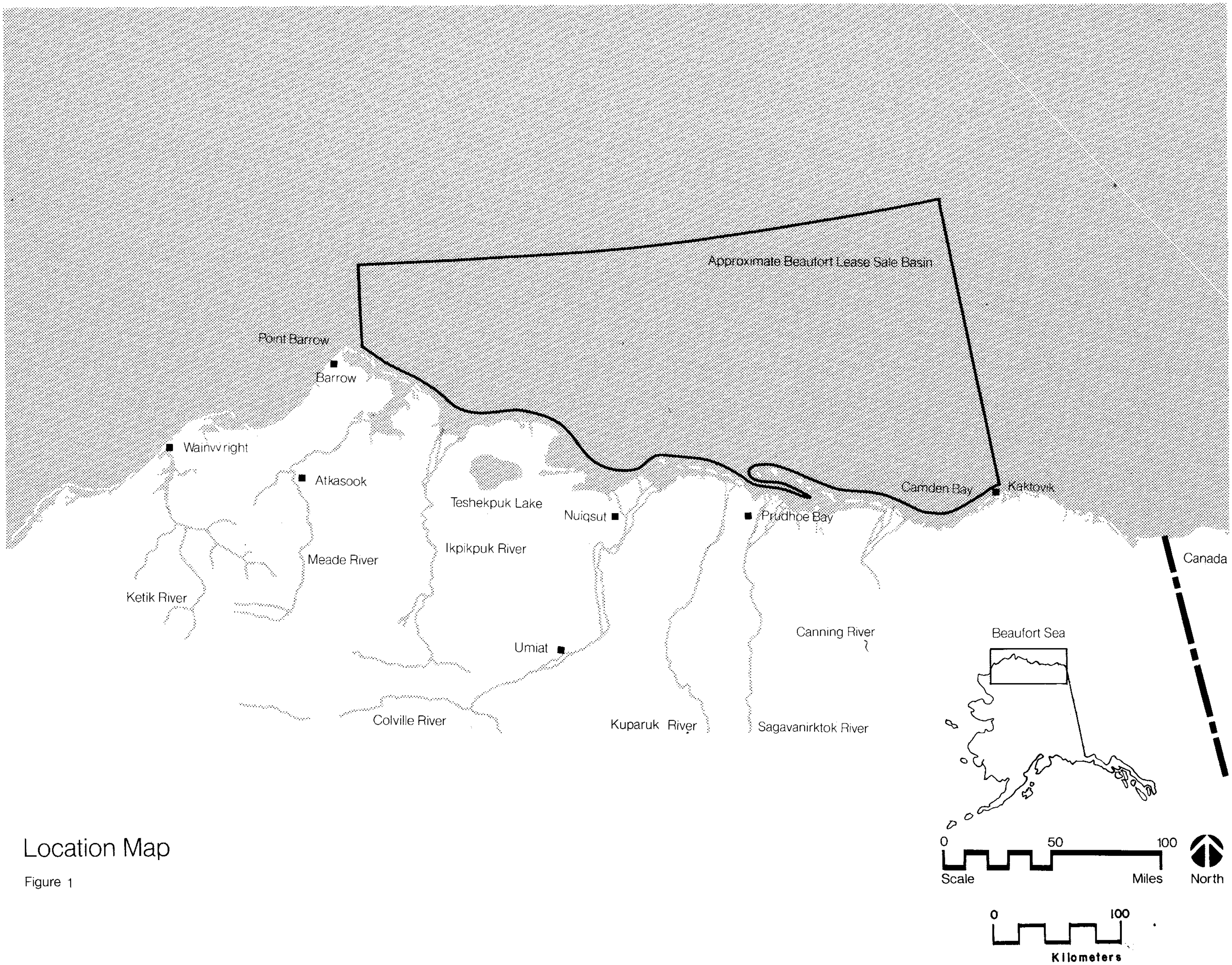
The petroleum development scenarios formulated in this report are for the proposed federal lease sale area located in the Beaufort Sea. Although this area has yet to be precisely defined and the tracts that will ultimately be leased are unknown, the lease area considered in this report encompasses that portion of the Beaufort Sea located between Barter Island (144° W) and Point Barrow (156° W) and extending seaward from the three mile limit to about the 20 m (60-foot) isobath. The significance of 20 m (60-foot) isobath is that it is the water depth believed to be the limit of present or imminent technology for exploratory drilling and production. This is because the 20 m (60-foot) isobath marks the approximate landward boundary of significant ice movement and encroachment of the seasonal and polar pack ice. The study area is shown in Figure 1, Location Map.

The area of the Beaufort Sea within the three mile limit comes under the jurisdiction of the State of Alaska and will be the location of a state or state-federal lease sale. Such a lease sale, which will probably occur before a federal sale, is not considered in this analysis. Moreover future petroleum developments in National Petroleum Reserve - Alaska (NPR-A), which is currently being evaluated by an exploratory drilling program, are not fully evaluated in this report; nor are they directly considered in the economic analysis. The reason for this exclusion is that future study efforts will expand the scenario scope to include all North Slope development; this report is therefore interm in nature.

This report does, however, consider the Prudhoe Bay development, Alyeska pipeline and the proposed Arctic Gas, Northwest and El Paso gas pipeline projects, which provide important economic data relevant to the analysis*.

The basis of this report is the U.S. Geological Survey estimates of undiscovered recoverable oil and gas resources of the Beaufort Sea between the O and 200 m isobaths as described in Circular 725 (Miller et al.,

*Subsequent to completion of this study the Northwest (Alcan) gas pipeline project has been selected by President-Carter and approved by Congress and the Arctic Gas and El Paso proposals have been withdrawn.



Location Map

Figure 1

1975). These estimates, which include the lease area under considerations in this report, are:

	Probability 95%	5%	Statistical Mean
Oil (billion of barrels)	0	7.6	3.28
Gas (trillions of cubic feet)	0	19.3	8.2

For the federal OCS lease sale discussed in this report, the following estimates of undiscovered recoverable oil and gas resources have been made by the U.S. Geological Survey (Grantz et al., 1976):

Oil (billions of barrels)	o to 3.9
Gas (trillions of cubic feet)	o to 9.9

These approximate the 5 and 95 percent probability levels.

METHODOLOGY

As stated above, the construction of the petroleum development scenarios is based upon the building block of the U.S. Geological Survey resource estimates. The initial scenario construction in Chapter II generates 15 scenarios based upon one of five unique levels of reserve concentration distributed in three arbitrarily chosen geographic locations (east, central and west) of the Beaufort Sea.

The technical framework of the scenarios established in Chapter II is based upon the technology review presented in Chapter I. That review describes available and potential Arctic petroleum technology in the context of the dominant environmental constraints (sea ice, permafrost, etc). The technical assumptions and related cost data also rely significantly on Alyeska experience and the proposed gas pipeline projects. Each of the 15 scenarios is subject to a parametric economic analysis which sequentially applies a range of economic variables (parameters) to the initial set of 15 scenarios. For each unique combination of parametric values (i.e. level of required investment, tax status, desired rate of return, transportation tariff, etc.) a determination is made of the required market price and minimum field size for commercial development. The process used for the economic analysis is shown schematically in Figure 3-1.

Criteria are established that permit the selection of the four scenarios to be elaborated in detail in Chapter IV. The criteria include: (1) the need for representation of all three geographical areas and four levels of reserves among the selected scenarios, (2) economic feasibility of both oil and gas development as determined by the economic framework of Chapter III, and (3) representation of the “maximum development” scenario with respect to the impacts of development on the physical and social environment. These criteria are sequentially applied to the fifteen scenarios, resulting in a unique set of four that meet all the above conditions.

Each of the selected scenarios is then described in detail in Chapter IV according to locational factors, facilities, equipment and manpower requirements. Scenario scheduling is presented and described for exploration, development, production and shutdown phases of petroleum development.

REGIONAL SETTING

To appreciate the physical setting of the petroleum region and potential OCS lease sale area discussed in this report, a brief description of the major physical features of the North Slope and Alaskan Beaufort Sea is appropriate. The petroleum region and adjacent OCS lease sale area are located within the Arctic Coastal Plain physiographic region which for the most part is a smooth plain that rises gradually from the Arctic Ocean coast to an elevation of 180 m (600 feet) in the foothills of the Brooks Range (Warhaftig, 1965). Located north of the Arctic circle, the American section of the Beaufort Sea extends from Demarcation Point (69° 40'N, 141° 00'W) at the Canadian border to Point Barrow (71° 25'N, 153° 30'W) in the west, a distance of approximately 610 km (380 miles).

The shoreline is also characterized by low relief with coastal bluffs generally less than 3m (10 feet) high. The Arctic Coastal Plain can be subdivided into two sections: the Teshepuk section which is a flat-lying lake-dotted plain, and the White Hills section, east of the Itkillik River, which is diversified by scattered groups of low hills. The coastal plain is at its narrowest near the Canadian border [about 18 km (11 miles)] and widens significantly westward toward Point Barrow where it is about 180 km (110 miles) across. Most of the coastal plain is underlain by unconsolidated silts and sands with some clays and gravels which comprise the predominantly marine Gubik Formation of Quaternary Age (Black, 1964). These deposits, which are up to 45 m (150 feet) thick, unconformably overlie Mesozoic sediments (shales, mudstones, sandstones) west of the Colville River and Tertiary rocks east of the river.

The coastal plain is underlain by continuous permafrost up to 610 m (2,000 feet) thick. The continuous permafrost coupled with the low relief result in the generally poor drainage and the development of patterned ground, thermokarst features and ice-cored mounds such as pingos. One of the most unique features of the coastal plain is the thousands of lakes which cover an area of approximately 435,000 square km (168,000 square miles); many of these lakes are oriented with their long axes a few degrees west of north.

Drainage on the coastal plain is predominantly north to the Arctic Ocean with the major rivers having their headwaters in the Brooks Range. The Colville is the largest of these rivers being over 690 km (430 miles) long and draining about 30 percent of the Arctic Slope. West of the Colville the rivers on the coastal plain are generally shallow, poorly-integrated and have meandering channels. In contrast, the rivers east of the Colville generally exhibit braided patterns and have numerous gravel and sand bars interspersed with continuously shifting channels.

An important result of these contrasts is the regional availability of sand and gravel. West of the Colville River, which intercepts much of the drainage and coarse sediments from the Brooks Range, gravel and sand are in short supply whereas east of the Colville many of the rivers originate in the Brooks Range and transport coarse sediment. The most significant hydrologic characteristics of the coastal plain are the virtual cessation of flow during the winter, the concentration of most of the season’s flow in a short period of time, and the inclusion of large amounts of ice in river flow usually during peak discharge (Walker, 1973).

The Beaufort Sea coastline is varied comprising such features as beaches, barrier islands, barrier bars, spits, lagoons, dunes and river deltas (Hartwell, 1973). Low but steep sea bluffs in many places are under active retreat as a result of a combination of thermal and wave erosion during the short summer open-water season.

The continental shelf of the American Beaufort Sea is narrow [no more than 95 km (59 miles) wide] and terminates at the edge of the continental slope in water depths of 45 to 70 m (150 to 220 feet). The shelf remains shallow for considerable distances offshore; at Harrison Bay, for example, the 20 m (60-foot) isobath lies as much as 73 km (45 miles) offshore. The waters in the eastern American Beaufort get deep much more quickly; the 20 m (60-foot) isobath at Camden Bay, for example, lies only 18 km (11 miles) from shore.

More detailed information on the physical features and environment of the North Slope and Beaufort Sea are available in such comprehensive references as <u>Alaskan Arctic Tundra</u> (Britton, 1973), <u>The Alaskan Arctic Coast</u> (Arctic Institute of North America, 1974) and <u>The Coast and Shelf of the Beaufort Sea</u> (Reed and Sater, 1974).

CHAPTER I

TECHNOLOGICAL AND ENVIRONMENTAL BACKGROUND

1.1 INTRODUCTION

The purpose of this chapter is to describe the environmental constraints that petroleum development in the Beaufort Sea will face and relate those constraints to the technology that will be required to explore, develop and produce petroleum in this region. In order to formulate petroleum development scenarios for the Beaufort Sea, it is necessary to predict the most probable equipment, materials and manpower requirements, i.e. compile a technology model for Beaufort Sea operations. Such information will form the basis of the scenario technical assumptions presented in Chapter 11 and cost data in Chapter III.

The physical and environmental conditions that may present constraints to offshore petroleum development are described in Section 1.2. These include sea ice, subsea permafrost, bathymetry, waves and storm surges, and climatic extremes. The technological considerations of petroleum development are reviewed in Section 1.3 which describes offshore drilling technology, oil field operations, oil processing technology and pipelines. Particular reference is made to design and selection of offshore drilling structures since this technology will probably diverge significantly from that utilized in other frontier areas of oil exploration. The problem of oil spills in the Beaufort Sea is an important consideration in any evaluation of offshore petroleum development. This is discussed with particular reference to sea ice conditions in Section 1.4.

Specific environmental conditions that relate to onshore locational factors of petroleum development are discussed in Section 1.5. These include natural environmental conditions, resources, and land use planning regulations.

To fully appreciate the unique problems of petroleum development in the Arctic, specifically the Beaufort Sea, it is necessary to list some of the geographic and environmental contrasts with other frontier petroleum development regions, such as the Gulf of Alaska and North Sea. These include:

- The continental shelf of the Beaufort Sea is shallow terminating at about the 60 m (200-foot) isobath. Initial exploration will probably take place in water depths of less than 20 m (60 feet) as compared with water depths of over 150 m (500 feet) in the Gulf of Alaska.

- There are no deep-water ports or deep-water port sites on the Beaufort coast. Numerous potential deep-water ports exist within the Gulf of Alaska and along the shores of the North Sea.

- Sea ice presents major constraints to offshore petroleum activities and marine transportation throughout much of the year. Although sea-borne glacial ice drifts in some areas of the Gulf of Alaska, there are no areas ice-bound as are common to the Beaufort Sea.

- With the exception of the trans-Alaska pipeline and haul road, no permanent onshore, land-based transportation infrastructure exists. Numerous transportation networks exist in the areas surrounding North Sea development.

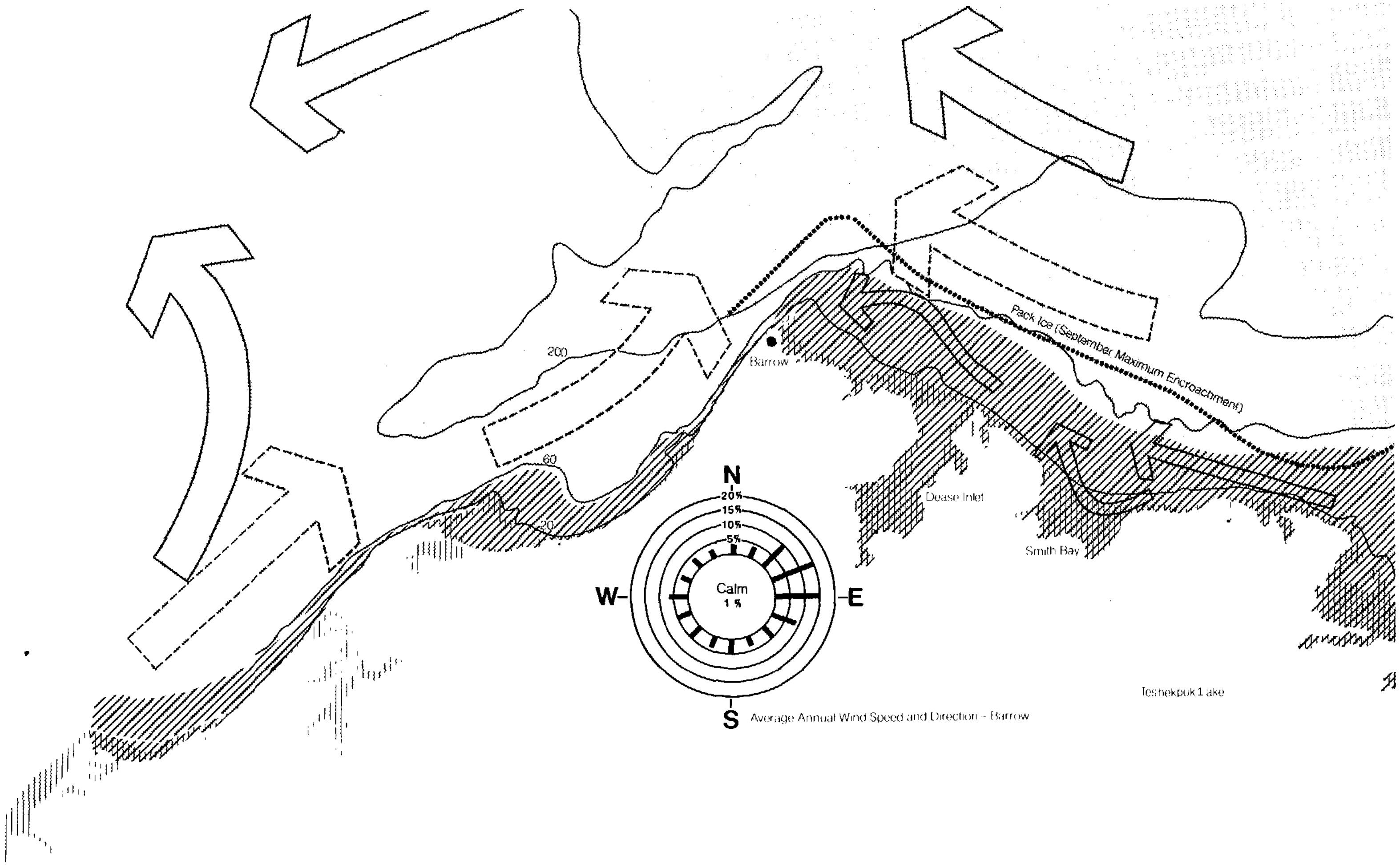
- Oil and gas markets are removed from potential oil and gas reserves by distances measured in hundreds of miles greater than similar areas of either the Gulf of Alaska or North Sea.

- With the exception of Prudhoe Bay, there is no local industrial infrastructure in contrast to the North Sea area and Kodiak Island area of the Gulf of Alaska.

Much of the petroleum technology (exploration and production) developed in the ice-free, deeper waters of the North Sea, therefore, is not directly applicable to the Beaufort Sea. With the exception of Canadian Arctic offshore operations in the Beaufort Sea, Arctic Islands, Davis Strait and Labrador Sea, there is little previous experience to draw on in formulating predictions of the technology and economics of Beaufort Sea petroleum development.

1.2 ENVIRONMENTAL CONSTRAINTS

The Beaufort Sea environment presents several significant constraints to petroleum exploration and development. Foremost of these is sea ice and its movement. Other factors include subsea permafrost, temperature, wind, waves and storm surges. Some of these features are shown in Figures I-1a and I-lb.



Environmental Constraints -West

60 Isobaths in Feet

Normal Current (Near Surface) Speed 0.5 Knots

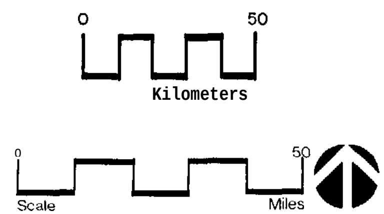
Near Shore Currents Weak and Unpredictable Wind Dependent Speed 0.5 Knots

Summer Current in Either Direction Along Coast

Subsea Ice bearing Permafrost Generally Present at 1 20 ft

Extent of Shore fast Ice

Figure 1-1a



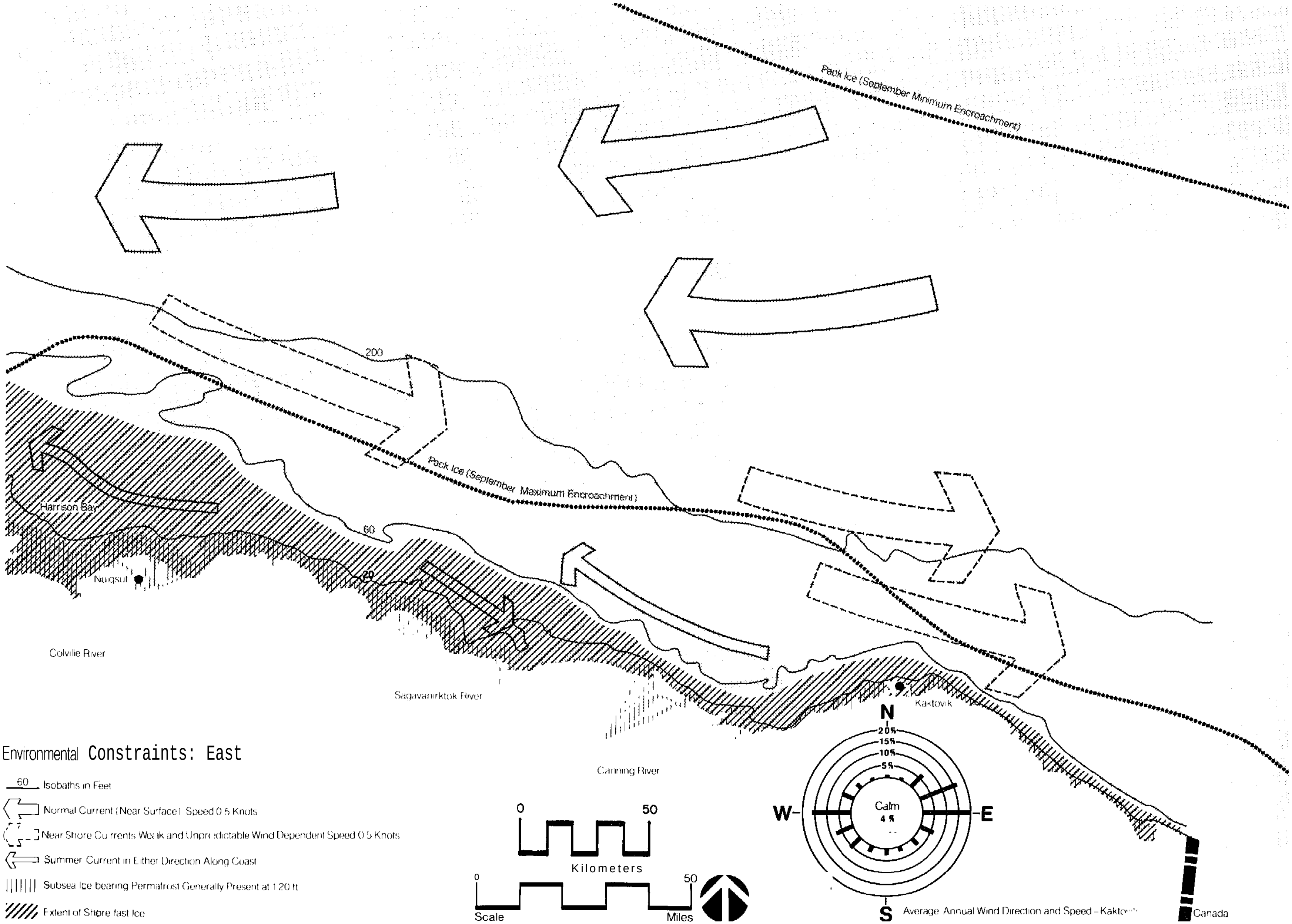

Pack Ice (September Minimum Encroachment)
Pack Ice (September Maximum Encroachment)
200
60
20
Harrison Bay
Nuiqsut
Colville River
Sagavanirktok River
Canning River
Kaktovik
Canada
N
S
W
E
20%
15%
10%
5%
Calm
4 %
Average Annual Wind Direction and Speed – Kaktovik
0
50
Kilometers
0
50
Scale
Miles
Environmental Constraints: East
60 Isobaths in Feet
Normal Current (Near Surface) Speed 0.5 Knots
Near Shore Currents Weak and Unpredictable Wind Dependent Speed 0.5 Knots
Summer Current in Either Direction Along Coast
Subsea Ice bearing Permafrost Generally Present at 120 ft
Extent of Shore fast Ice

Figure I-1b

1.2.1 Sea Ice

The seasonal growth, movement and decay of sea ice in the Beaufort Sea is governed by the motion of the polar pack ice interacting with the coastline, as well as the interplay of the major rivers, such as the Colville and Sagavanirktok, and the climate.

In winter, sea ice can be divided into three general zones: (1) fast ice zone, (2) seasonal pack ice zone, and (3) polar pack ice zone (Kovacs and Mellor, 1974). In general , only the fast ice zone will occur within the proposed developable region of the OCS lease sale area (i.e., approximately out to the 20 m isobath), but even this region will experience frequent encroachment of the pack ice during the early period of growth (i.e. fall). It must be emphasized that ice conditions of any one year do not necessarily represent those of the next. Conditions are so variable that such terms as "average ice conditions" have no real significance.

Fast ice begins to develop in late September or October and thickens gradually throughout the winter to 2 m (6 feet) or slightly more in late March or April. Close to shore the ice is usually relatively undeformed and for the most part will rest on the shallow sea bottom.

The polar pack ice, consisting mainly of multi-year floe ice, 2 m (6 feet) and more thick drifts westwards under the influence of the Beaufort Sea Gyre (a clockwise movement of polar pack ice which is the average motion imposed by mean wind stresses in the Arctic Ocean). Between the westward-moving polar pack ice and the fast ice is a transition zone of deforming, sporadically moving, ridged ice, which is referred to as the "stamukhi zone." The grounding of the pressure ridges and shear ridges that are formed in this zone is responsible for many of the extensive gouges or scours that commonly occur in water depths of 15 to 45 m (50 to 150 feet), and which have a maximum concentration at 30 m (100-foot) depth. Table I-1 summarizes scour zones in the southern Beaufort Sea.

Ice scour in the coastal shelf zone [less than 7 m (23 feet) deep] is caused by fragments of broken ice islands or other small pieces of ice; the scour may be very frequent but is generally shallow [less than 0.5 m (1.6 feet)] (Kovacs and Mellor, 1974). In the mid-shelf zone [7 to 30 m (23 to 90 feet) deep] considerable scouring is caused by the grounding of ice islands and/or pressure-ridge keels, and occurs with a frequency of 10 to 15/km (20 to 25/mile) and average depth of less than 1.5 m (5 feet). The outer shelf 30-80 m (100 to 250 feet deep), is characterized by scour relief up to 10 m (30 feet), but with a rapid decrease in frequency beyond 45 m (150-foot) depth. Most of the scouring in this zone is either relic or caused by ice islands.

Initiation of breakup in May and early June occurs when river flow commences and open water forms near river mouths and extends offshore. The fast ice becomes thinner and weaker and commences to break up in July. The open water season generally lasts until late September.

TABLE 1-1

BOTTOM ICE SCOUR ZONES

Region	Water Depths m (ft.)	Typical Scour Depthm (ft.)	Maximum Scour Depth m (ft.)	Frequency of Scour Tracks
Coastal Shelf	o-7 (0-20)	Less than 0.5 (2)	No data	Very frequent
Mid Shelf	7-30 (20-100)	Less than 1.5 (5)	3-4 (10-15)	10-15 per km (20-25 per mile)
Outer Shelf	30-80 (100-250)	No data	10 (32)	Slight beyond 45 m (1 50′) depth

After: Kovacs (1972).

The significance of sea ice to offshore petroleum development can be summarized as follows:

- There is only a short (2-1/2 to 3 months) ice free or open water season during which time conventional drilling structures and service vessels can operate. In terms of logistics, there is a short transportation season or "window" for ocean traffic into the Beaufort Sea from other areas of Alaska, the lower 48 states and overseas.

- During the initial phases of petroleum development, the stamukhi zone will probably establish the seaward limit of petroleum activities thereby restricting such activity to the fast ice zone.

- Offshore platforms will have to be suitably protected from the stresses of moving ice.

- Subsea pipelines will have to be protected from ice gouging; pipeline routing and design will in part be based upon data on scour depth, distribution and recurrence.

1.2.2 Bathymetry

The continental shelf of the American Beaufort Sea is narrow [no more than 80 km (50 miles) wide] and breaks at a depth of 45 to 70 m (150 to 220 feet). The shelf remains shallow for considerable distances offshore; at Harrison Bay, for example, the 20 m (60-foot) isobath lies as much as 72 km (45 miles) offshore. The waters in the eastern Beaufort get deeper much more quickly; the 20 m (60-foot) isobath at Camden Bay, for example, lies only 18-1/2 km (11 miles) from shore.

The significance of the Beaufort Sea bathymetry to petroleum development is that, unlike other frontier petroleum regions (e.g. North Sea on Gulf of Alaska), the water remains shallow for relatively great distances from shore. This factor favors the utilization of man-made islands (ice or soil) and, ignoring ice conditions, does not favor the utilization of semi-submersible drilling rigs or concrete production platforms of the type that have been used in the North Sea.

1.2.3 Subsea Permafrost

Sub-seabottom permafrost exists over much of the Beaufort Sea shelf (Hunter, et al., 1976; MacKay, 1972). In the southern Beaufort Sea, permafrost thicknesses from 60 m (200 feet) at shore to 100 m (330 feet) offshore have been reported. At Prudhoe Bay, ice-bonded permafrost exists nearly up to the sea bed within 200 m (650 feet) of the shore and, at 3.2 km (2 miles) from the shore there is an unbended layer 45 to 70 m (150 to 230 feet) thick (Osterkamp and Harrison, 1976). Subsea permafrost at Prudhoe is present to at least 3.4 km (2.1 miles) offshore.

At Prudhoe Bay, permafrost is found in thick unbended (non-ice-rich) layers at water depths greater than 2 m (6 feet). This indicates that permafrost will probably not cause serious problems for foundations and pipelines; and standard construction techniques may be employed. However, in water depths less than 2 m (6 feet), permafrost is found in ice-bonded layers; and the potential exists for damage to a hot oil pipeline through development of a thaw bulb, or to a chilled gas pipeline by differential freezing and frost heave. Other problems or considerations related to subsea permafrost and petroleum development include:

- Dredging operations may be difficult in areas of near-bottom subsea permafrost; dredging may expose permafrost, modify the thermal regime and create settlement or heave problems.

- The presence of subsea permafrost will have to be taken into consideration in the design of port facilities.

- Exploratory drill holes, in some cases, will have to be specially cased to maintain the integrity of the hole. Similarly, production wells may have to be special cased when several are located close together.

1.2.4 Wave and Storm Surges

Particularly important with respect to the design of artificial soil islands, which have a low freeboard in comparison to other drilling platforms and have to be protected from erosion, are waves and storm surges.

Surface waves are restricted to the summer open water season and are generally small; ordinary wind waves have periods of 2 to 3 seconds and heights less than 1 m (3 feet). This is because of the limited fetch resulting from the offshore sea ice. Maximum swell heights of

1.5 to 2 m (5 to 6 feet) with periods of 9 to 10 seconds have been reported during a summer storm (Wiseman, et al., 1974).

Storm surges, that is, storm-induced increases in sea level, have been recorded in the southern Beaufort Sea, and may exceed 2 m (6 feet) in height (Henry, 1975). Design of production structures and port facilities will have to take these surges into consideration.

1.2.5 Climatic Extremes

Darkness, cold, wind, snow, ice, permafrost, ice breakup, swampy summer tundra, fog, insects, limited transportation and vast unpopulated areas are among the many factors which affect living conditions in the Arctic and, for most men, result in decreased working efficiency. For ten months of the year average air temperatures are cold along the Beaufort and Chukchi Sea coasts varying from -21°C to -37°C (-6°F to -36°F). Moreover, persistently moderate, [24-32 kph (15-20 mph)] to high [> 24 kph (25 mph)] winds combine with low temperature to make outdoor activity uncomfortable, difficult, and at times impossible. It is not unusual during the dark mid-winter months to experience an “equivalent chill temperature” of -13°C (-10°F) and more -- during which times exposed flesh may freeze within 30 seconds. Likewise in summer, although temperatures range from about -1°C to 7° C (+30°F to +45°F) [extremes reaching over 24°C (> 75°F)], a wind of 32 kph (20 mph) will produce an “equivalent chill temperature” of about -12°C (+10°F).

Wind chill is an important consideration and can seriously hamper field operations. Coveralls, headgear and footwear worn by personnel working offshore and on the beach must be insulated or supplemented by insulation of some kind. There are many ways to achieve this, but it will most likely mean adding weight and bulk, which to some extent restricts mobility and therefore efficiency. In summer, low clouds, fog, the tundra environment, and insects add to the decline in modern man's efficiency. Yet in the last three decades, civilization of the Arctic has been rapidly accelerated, first by the influx of the military (construction and operation of the DEW Line stations), and more recently by the arrival of the oil industry.

1.3 TECHNOLOGICAL CONSIDERATIONS

1.3.1 Offshore Drilling Structures

1.3.1.1 Introduction

This section describes the various offshore drilling structures and techniques that may be available to the oil industry in the Beaufort Sea OCS lease sale area. These options are discussed in the context of the dominant environmental constraints, It should be emphasized that many of the technological options described herein are in the conceptual, design, or prototype stage of development; and thus, may require considerable lead time before introduction into an offshore petroleum development program.

Particular reference is made to the Canadian experience in the southern Beaufort Sea and Arctic Islands, since they are the only regions with significant offshore Arctic petroleum activity to date. This experience includes:

- Exploratory drilling in the southern Beaufort Sea utilizing soil islands, sunken barges and ice-strengthened drillships;

- Drilling from reinforced ice platforms off the Arctic islands; and

- Advanced technological research in all phases of Arctic offshore petroleum-related activities.

In contrast, the American Beaufort experience is limited to two ice islands near the Colville delta (Union Oil) and several wells drilled from gravel pads in shallow water in Prudhoe Bay.

Data on offshore petroleum technology described in this report primarily comes from industry journals such as <u>The Oil and Gas Journal</u> which have sections devoted to technology. Several journals deal exclusively with marine and offshore activities such as <u>Offshore</u> and <u>Ocean Industry</u>. The collected papers of the annually-held <u>Offshore Technology Conference</u> examine problems relating to offshore petroleum and mining technology, marine sciences and environmental problems. In recent years there has been an increasing number of papers devoted to Arctic operations.

There are few references which provide a comprehensive discussion on offshore Arctic petroleum operations. Brown (1976) presents an overview of Canadian operations. An assessment of technological options and environmental constraints to offshore Arctic operations is contained in <u>Prototype Beaufort Sea Technology Scenario</u> (Clarke, 1976). That report breaks down the Alaskan Beaufort Sea into offshore zones characterized by such factors as distance from landforms, water depth and ice conditions, and relates them to various technology options. The Alaska Oil and Gas Association (AOGA) Arctic Research Subcommittee has summarized technological capabilities and Arctic experience in Offshore Exploration and Production Industry Operating Capability in the Beaufort Sea (AOGA, 1975b). Potential Beaufort Sea petroleum development, equipment, materials and manpower requirements are discussed in Data for State of Alaska Socio-economic Impact Assessment of Leasing in the Beaufort Sea (AOGA, 1975a), which summarizes the development of Prudhoe Bay. A brief summary of Arctic technology is contained in A Preliminary Development Scenario for a Potential Beaufort Sea Lease Sale (Bureau of Land Management, 1977).

There is a considerable body of data on offshore technology and the Arctic environment that has been sponsored by AOGA and its Canadian counterpart, the Arctic Petroleum Operators Association (APOA). Much of the data, particularly that relating to technology, is however, proprietary.

1.3.1.2 Artificial Islands

Artificial islands are generally constructed from locally mined soil (gravel , sand, silt) with or without bonding or cementing agents and suitably protected to resist ice forces and wave and current erosion. An artificial island may be designed as a temporary structure for an exploratory well or as a permanent production platform with long-term protection against ice and waves.

Artificial islands are basically comprised of two parts: (a) the body of the island which forms the base for drilling operations with a minimum surface radius of 50 m (160 feet); and (b) side slopes designed to protect the island from waves in summer and ice in winter (de Jong, Steiger and Steyn, 1975; Ocean Industry, October 1976c).

Slope protection materials that are normally utilized, such as concrete blocks, quarry stone and bitumen mixtures, are very expensive in the Beaufort Sea due to transportation distances. Short-term structures such as exploratory islands, however, can utilize such temporary methods as:

- Sand bags
- Gabions (wire mesh enclosures) filled with sand bags
- Sand-filled plastic tubes, and
- Filter cloth held down by wire netting

To date, artificial islands in the southern Canadian Beaufort have been built in water depths of less than 15 m (50 feet), although such structures may be feasible in water depths up to 20 m (60 feet) [two islands were constructed in the summer of 1976 including one in a water depth of about 12 m (40 feet)].

Artificial islands constructed as drilling platforms for exploratory wells can also be designed with sufficient reinforcement for ice and wave protection to serve as permanent production structures. In nearshore areas, production platforms could be linked to the mainland by causeway systems which would serve as both pipeline corridors and supply roads. As with exploration islands, production islands may be feasible to a maximum water depth of 20 m (60 feet) with such protection as sheet piling. In addition to their restriction to the landfast ice zone, a major factor in the feasibility of artificial soil islands is the increasing quantity of gravel or sand required with increasing water depth, and hence increasing construction costs. The use of sheet piling can reduce the material required and therefore make deeper water islands more economically feasible.

In the Mackenzie Delta section of the Beaufort Sea, Imperial Oil Ltd. has constructed eight artificial islands for its exploratory drilling program (Riley, 1975). The factors which favored this type of structure were:

- Shallow water--the lease acreage (Imperial Oil Ltd.) extends to about the 20 m (60-foot) isobath. Minimum sea ice movement--most of the acreage of interest lies within the landfast ice zone.

- Very high standby costs for floating rigs during the winter due to the short working season (2-1/2 - 3 months).

- Islands were considered to be the safest means of resisting ice forces.

- The initial capital investment for most other types of structures was considered to be high compared with artificial islands. This is especially important when the number of prospective locations is small and very dependent on the ratio of success.

- Construction of artificial islands is a proven technology utilizing standard construction equipment.

- Environmental laws in Canada favor this approach and do not require the removal of these islands after their use for unsuccessful exploratory drilling.

- Also environmental restriction in Canada are significantly less regarding sand and gravel sources offshore.

Three basic designs have been employed by Imperial Oil to date:

- Immerk type--constructed of granular fill, hydraulically placed by suction dredge constructing a natural slope of 1:20. The Immerk B-48 island was built during two summer construction seasons by pumping sand and gravel from a submarine borrow site directly onto the island site. The island was built to a height of 4.5m (15 feet) above sea level in 3 m (10 feet) of water.

- Netserk type--mechanically-placed granular fill was dumped inside a retaining ring of sand bags and outside forming side slopes of 1:3. Netserk B-44 was built in 4.5 m (15 feet) of water and utilized sand dredged from a borrow site 32 km (20 miles) from the island. A second island, Netserk NF-40, was built in the same manner but in 7 m (23 feet) of water. Netserk was designed for one season year-round drilling.

0 Adgo type--built primarily of silt which was placed within a retaining wall of sand bags by clamshell equipment. Adgo F-28 and P-25 were constructed for winter season operations only and depended upon freezing of silt to provide stable bases for equipment. Adgo F-28 and P-25 were built with a limited freeboard to mean sea level (MSL) of +1 m (+3 feet) in 2 m (7 feet) of water.

Two islands, Adgo C-15 and Pullen E-17, were built during the winter season by trucking sand and gravel over the ice from shore borrow sources to the proposed island sites. Ice was cut and removed in blocks and the excavation backfilled with sand and gravel. Slope protection was provided by small sand bags. The islands were constructed to an elevation of MSL +3 m (+10 feet) so that they could be used during the summer.

An example of the material requirements for a gravel island is provided by Sun Oil's Unark island constructed in the winter of 1973-74 in 3-1/2 feet of water in the Canadian Beaufort Sea off the Mackenzie Delta (Brown, 1976). The island required 43,580 cubic meters (57,000 cubic yards) of gravel, 91,475 sand bags, 3,760 square meters (40,500 square feet) of chain link fence, and 3,760 square meters (40,500 square feet) of filter cloth.

Assuming an average water depth of 9 m (30 feet) and a freeboard of 3m (10 feet), gravel requirements for a three acre exploratory island and seven acre production island would be approximately 152,000 cubic meters (200,000 cubic yards) and 344,000 cubic meters (450,000 cubic yards) respectively.

A variant of the artificial island discussed above, which may have Arctic applications, is a prototype sand island field tested off the south coast of England in 1976 (Ocean Industry, November 1976). The island, which could also be classified as a gravity structure, comprised an impermeable rubber membrane filled with hydraulically placed sand supporting a deck unit. The membrane and deck were fabricated on land and towed to the site [15 m (50 feet) water depth] where the fill was placed. Installation on site took less than 48 hours.

The design of the island was based upon the principle that at any depth below the sea surface, the lateral pressure exerted by the sand is about half that of the confining hydrostatic pressure. Thus, the sand behind the membrane will always be stable provided pore water pressure is relieved; this is done by dewatering the sand through pumping during placement of the fill and, when necessary, during operation by a permanent pumping system. The dynamic response or energy absorption of the sand island occurs through microstraining of the sand particles. This energy absorption within the sand mass reduces the loading transmitted to the structure foundation.

Unfortunately, the prototype, christened "Sandisle Anne," was sunk during a storm in October 1976 which brought 10.6 m (35-foot) waves--over 50% higher than the 6.4 m (21-foot) waves predicted (Ocean Industry, December 1976). No costs have been given for construction of this type of sand island.

Two other types of ice-resistant versions of this sand island have been designed. One consists of two concentric retaining walls; the other an outer wall sand structure surrounding a conventional gravity structure.

In both cases, the outer sand structure absorbs the shock while the inner concrete or sand column supports the deck. The deck unit would be designed to break the ice.

Review of the literature pertaining to construction of artificial soil islands in the Beaufort Sea leads to the following conclusions:

- Design problems have been solved for temporary soil islands in depths of water up to 12 m (40 feet).

- Artificial soil islands with sheet piling are probably feasible to water depths of 20 m (60 feet).

- For the island body, silt, sand and gravel have been utilized, although sand and gravel are the preferred materials.

- Construction by suction or dredging is normally conducted in the open water season; however, winter construction, consisting of ice removal and back-filling with fill transported over the ice by trucks, has been conducted.

- For shallow water, artificial soil islands, along with ice islands and sunken barges, are the only offshore drilling structures that do not require an extensive lead time for development.

- Costs are lower than other alternatives for the shallow water, landfast ice section of the southern Canadian Beaufort Sea.

- Artificial soil islands may only be feasible within the Alaskan Beaufort Sea within the landfast ice zone, since the islands may not be able to withstand the ice forces of the stamukhi zone (de Jong, Steiger and Stein, 1975).

Although the feasibility of artificial soil islands in the shallow landfast zone of the southern Beaufort Sea has been proven, there are several environmental concerns that may have to be addressed and studied in detail before extensive use of such structures is made in the Alaskan Arctic OCS. These problems include:

- The availability of offshore and onshore borrow materials.

- The impact of dredging, particularly siltation, upon benthic and other organisms.

- Impacts resulting from the modification of erosion and sedimentation patterns by dredging, and by the construction of islands and causeways.

- Effects of the substantially greater ice movement in some of the Alaskan Arctic OCS areas compared to Canadian Beaufort Sea experience.

0 Disturbance of marine mammals by marine construction traffic (see Section 1.5).

0 Waste disposal including drilling mud, cuttings, solid waste, sewage and domestic waste.

1.3.1.3 Reinforced Ice Platforms

There are two types of reinforced ice platforms that have been produced by thickening of the parent ice sheet through successive flooding of its upper surface. In shallow water, successive flooding and freezing of water on top of the parent ice sheet rapidly thickens and eventually grounds the sea ice. Drilling can then be conducted from the thickened and grounded ice sheet. In deeper water, this thickening technique has been used to gain the requisite buoyancy to support exploratory drilling equipment.

A conceptual extension of the grounded ice sheet is an artificial ice island. Construction of the ice island involves thickening of the ice sheet to a height above sea level required to (a) protect the island's surface from ice rafting and waves, or (b) provide sufficient bottom-contact stress to resist horizontal movement due to moving ice forces. The most suitable location for an ice island is in the fast ice zone where, by January, ice is about 0.6 m (2 feet) thick, making over-ice transport possible. Since the number of ice-making days is limited (40 to 50 days at 50 percent operating time from January through May), spraying or sprinkling has been suggested in order to encourage growth rates (Fitch and

Jones, 1974). Construction of an ice island 120 m (400 feet) in diameter and 20 m (60 feet) thick could probably be accomplished in one winter season. The cost of building such an ice island, excluding development costs has been estimated at less than $5 million (Fitch and Jones, 1974).

In the American Beaufort Sea, ice islands have been pioneered by Union Oil Company of California which constructed a prototype during the winter of 1975-76, and an operational island from which an exploratory well was drilled during the winter of 1976-77 (Duthweiler, 1977). These islands, which were located about three miles west of Oliktok Point near the Colville River delta, consisted of an outer ice ring [140 m (450 feet) inside radius] and an inner rectangular drill pad [60m (200 feet) by 120 m (400 feet)]. Surface flooding was utilized to form the ice-thickened drill pad and outer ring which were grounded on the sea floor. The natural ice thickness was 142 cm (56 inches) and the water depth was 2.5 to 3m (8 to 10 feet). Construction of the 1976-77 ice island took from November 1 to January 15 and the well was drilled from January 20 to April 1. The prototype island broke up on July 2 and the second island is expected to break up near the same date.

The construction spread for both islands was minimal relative to the normal equipment demands of a land-based North Slope exploratory well.

In the Canadian Arctic islands, where the Arctic Ocean is covered with ice 10 to 11 months of the year, Panarctic Oils Ltd. has to date (1976) completed five wells in up to 286 m (940 feet) of water. These wells are about 22.5 km (14 miles) from shore and were drilled from reinforced ice platforms (Brown, 1976). The Panarctic program was pioneered by the

Helca N-52 well located off the Sabine Peninsula of Melville Island. It was drilled by a conventional Arctic Rig with a subsea blow out preventer (BOP) stack and riser (Baudais, Watts and Masterson, 1976). The ice sheet was artificially thickened from 2 to 5 m (6 to 16 feet) by free flooding with sea water over a period of 42 days. The single most important factor governing the feasibility of drilling from an ice platform is horizontal ice movement. Consequently, such platforms are restricted to areas of landfast ice where horizontal ice movement is no more than 5 percent of the depth of water over the design life of the island. The main disadvantage of the ice platform system in this part of the Canadian Arctic Ocean is the time limitation (and hence depth of well completion) imposed by the length of the season of minimal ice movement (January to May). The construction completion date of the thickened ice platform is unlikely to be before the end of December. Also it should be noted that water depth must be great enough that pack ice damage to the BOP stack is not a problem.

1.3.1.4 <u>Ballasted Barges</u>

This technique employs a barge floated to the well location where it is then ballasted to sit on the sea floor. A gabion/sand bag-contained silt berm or sea ice thickening techniques are then used to provide protection against waves and ice.

The ballasted barge technique was utilized successfully in construction of Pelly artificial island located in 2.3 m (7-1/2 feet) of water off the Mackenzie Delta (Brown, 1976). The Pelly Island location consisted of a drilling barge, camp base, dredge and supply barges. The drilling rig was mounted on two rail barges, each 11 m (38 feet) by 73 m (240 feet), tied together with a superstructure to make a slotted barge 27 m (88 feet) by 73 m (240 feet) by 4m (14 feet). The artificial island was constructed with a gabion berm set on to the sea floor to form a rectangle 155 m (510 feet) by 64 m (210 feet). The berm served as protection against waves and as a retainer for silt fill which was placed around the drilling barge.

The drilling barge system has the advantage of mobility and extending the drilling season beyond that provided by an ice or gravel island.

1.3.1.5 Ice-Strengthened Drillships

Dome Petroleum currently has three ice-strengthened drilling ships operating in the Canadian Beaufort Sea (Jones, 1977). These ships, which were moved into the Beaufort in the summer of 1976, have the capability of drilling to 6,000 m (20,000 feet) in water depths between 30 m and 300 m (100 and 1,000 feet) (Brown, 1976). The drillships are 115 m (377 feet) long and 21 m (70 feet) wide with a light draft of 4 m (13 feet) and drilling draft of7 m (23 feet). Each have a dead weight of 5,486 metric tons (5,400 long tons).

In the drilling program, it was originally planned to utilize a work barge to install a 6 m (19 foot) diameter caisson (for BOP protection) before the drillships arrived on location. However, due to problems experienced during preliminary work in 1975, Dome utilized the simpler technique of placing well-heads and BOP stacks in scooped-out depressions in the sea floor out of reach of scouring ice (Jones, 1976).

The drillships were anchored at the drill site with a quick disconnect mooring system which permits rapid release and reconnection of the mooring lines in the event that a move off location is required due to ice or other factors. A drilling season of about 112 days from July to October was planned. However, in order to leave sufficient time to drill a relief hole in the case of an emergency, Canadian authorities limited the drilling season by setting a mandatory completion date before the projected end of the season (Jones, 1977). The 1977 drilling season is expected to be longer since the ships will have wintered in the area and drilling can begin immediately upon breakup without waiting for the freeing of the Point Barrow entrance to the Beaufort Sea.

The drillships are accompanied by four ice-breaker-supply ships which have the capability to break up to 1 m (3 feet) of solid sea ice. Each ship has the following specifications (Brown, 1976):

- Length--63 m (207 feet)
- Width--14 m (45 feet)
- Draft--4.4 m (14.5 feet)
- Cargo capacity--1,016 metric tons (1,000 tons)
- H.P.--7,000 twin screw
- Speed--26 kph (14 knots)

Ice-strengthened drillships could also be utilized in winter by maintaining an ice free "lake" in the landfast ice within which the ship could operate. Methods proposed to maintain an ice-free or thin ice areas up to 300 m (1,000 feet) in diameter include protective canopies, insulating agents, hot water, air bubble generators and the use of guardian ice breakers (Jones, 1977).

Another proposed drillship design is an ice breaking system using a pneumatically-induced pitching system (PIPS) which allows drilling while ice breaking (Ocean Industry, April 1976).

1.3.1.6 Gravity Structures

Gravity structures employ deadweight to develop frictional force on the sea bottom to hold against lateral movement. Alternatively or additionally, the structure may be held in position by anchors or piles. These structures can be floated to the site and ballasted on the sea floor. Several concepts or designs of gravity structures have been proposed--mainly mobile platforms for exploratory drilling in the Beaufort Sea. Adaptation and modification of various concrete designs utilized in the North Sea may be proposed for permanent production platforms in the Beaufort Sea. Gravity structures will probably be employed beyond the landfast zone and/or in deeper water [greater than 12 m (40 feet)] where artificial islands are not feasible or economic. Briefly described below are some of these designs, none of which, it should be emphasized, have progressed beyond the design or prototype stage.

1 .3.1.6.1 Monopod

The monopod platform is one configuration of a variety of gravity structures that are grounded on the sea floor after being floated to the site. The base of the platform may be attached to the sea floor by piles.

Of the various gravity structures currently in use or designed, the monopod configuration may be the most suitable to resist ice forces. Imperial Oil of Canada has designed a monopod platform for year-round exploratory drilling in the southern Beaufort Sea (Brown, 1976). This monopod comprises a one-legged platform supported by a broad submersible base and is designed for the environmental and soil conditions existing out to 12 m (40 feet) water depths. The monopod structure consists of three main components: the hull, the shaft and superstructure. On location, only the shaft is exposed to ice loading since the hull is totally concealed in a previously prepared excavation on the sea floor. The monopod is set down on the sea floor or floated by ballasting or deballasting. Beyond 12 m (40 feet) water depths, it is postulated that concealment of the hull may not be required because the possibility of interaction between the hull and pressure-ridge keels is remote.

A mobile gravity structure such as the monopod provides operating flexibility and could probably operate in greater water depths than can be served by gravel islands. All of the well casings must be placed in the single shaft.

1.3.1 .6.2 Cone

An alternative configuration to the monopod is a cone which causes a moving ice sheet to ride up and fail in tension with both radial and circumferential cracks (Gerwick, 1970). In order to prevent excessive ice ride-up, the cone would recurve at the top. Considerable research on the cone structure, including model testing with ice, has been conducted by Imperial Oil Ltd. (Canada), under a coordinated program of arctic research sponsored by the Arctic Petroleum Operators Association (APOA). A cone structure could be of concrete construction designed to be ballasted onto the sea floor.

A variant of the cone design is an "ice island" (not to be confused with a thickened ice sheet) which consists of a 76 m (250 feet) tall hour-glass shaped steel-plated platform capable of operating in waters up to 20 m (60 feet) deep (Oil and Gas Journal, 1970). The steel plate shell would be supported by ice-filled tubes in compartments. The structure would be floated to location during the open water season and ballasted to the bottom with sea water, which would then be refrigerated to provide the strength for additional resistance to ice forces. Refrigeration requirements have been calculated for initial freezing and for maintenance of the ice through the winter and following summer seasons. To move off location to another drilling site, the frozen fill would be thawed, and the internal compartments emptied. Cost of this structure was estimated at $40 million in 1970.

1.3.1.7 Other Structures

There are several offshore drilling systems proposed for Arctic areas that are in the conceptual or design stages.

One such system is a semi-submersible drilling rig design studied by the Arctic Petroleum Operators Association (APOA). The design consists of a lower hull located well below the water surface, a monopod column supporting an ice cutting cylinder, and a superstructure containing the drill, crew quarters, etc. The semi-submersible is envisioned to be a self-propelled and dynamically positioned drilling system. In shallow water areas, the semi-submersible system could be employed as a gravity structure resting on the sea floor by ballasting.

Other systems such as conventional semi-submersible rigs and jack-up platforms, which have not been used in the Arctic to date, could be used during the short open water season, or possibly during winter with added winterization and ice protection in some areas.

Another system is the dynamically positioned floating Arctic drilling platform, "Rock Oil", designed by a Norwegian engineer (Ocean Industry, March 1976). The platform comprises a partially submerged steel tank in the form of a 32-side rhomb, 113 m (370 feet) in diameter and a total height of 120 m (400 feet) from the bottom of the tank to top of the drilling derrick, supporting a deck and steel tower. A propulsion system with driving propellers set at the base of the tank 45 m (150 feet) below water level coupled with ballasting/deballasting capabilities would provide the structure with ice breaking capability.

For operation in landfastice areas, an Air Cushion Drill Barge (ACDB) has been proposed '(Jones, 1977). The ACDB comprises a drill rig mounted on an amphibious air cushion platform which can be utilized on ice or in a lake previously prepared in the ice sheet by removal of ice blocks.

1.3.2 Platform Design and Selection Criteria

1.3.2.1 Introduction

The selection of offshore structures in the Beaufort Sea OCS lease sale area will depend upon such factors as (a) environmental constraints, (b) stage of petroleum development (exploration, development, production),

(c) technology available, (d) logistics, (e) costs, (f) environmental legislation, and (g) resource availability.

1.3.2.2 Environmental Constraints

The environmental constraints that influence platform design and selection include:

- Sea ice
- Bathymetry
- Tides and currents
- Wind and waves
- Strength, thickness and movement of ice
- Soil mechanical properties of bottom sediments
- Subsea permafrost

Some of these factors have been described in detail in Section 1.2. To briefly reiterate, in the landfast ice zone to water depths of 12 m (40 feet), the use of artificial soil islands, ice islands/ thickened pads and sunken barges is feasible and uses currently developed techniques. Conventional semi-submersible and jackup rigs could be used for exploratory drilling during the open water season. However, lengthy mobilization and standby time coupled with a short drilling season may make these conventional systems uneconomic, unless suitably modified to take advantage of the winter season.

Artificial soil islands reinforced by sheet piles could extend the feasibility of soil islands to water depths of 20 m (60 feet) in areas still within the landfast ice zone at these depths.

With suitable refrigeration or insulation to minimize or prevent summer ablation ice islands could serve as production platforms. Such measures could also be utilized to increase the life-span (and hence drilling season) of an exploratory ice island.

Beyond the landfast ice zone or in water depths greater than 20 m (60 feet), ice-strengthened drillships and gravity structures with ice-cutting capabilities such as the monopod already described, would probably be the favored technological alternatives for exploratory drilling, and gravity structures probably the most suitable for production platforms.

In general the contrasts between the Canadian experience in the southern Beaufort Sea and the Alaskan Beaufort can be summarized as follows:

- Shallow water generally extends for greater distances offshore in the southern Canadian Beaufort than in the Alaskan Beaufort, especially when comparing the Canadian area east of the Mackenzie Delta with the Alaskan Beaufort east of Prudhoe Bay. While the maximum distances offshore of the 20 m (60-foot) isobath are comparable 72 km (45 miles), a much greater area per kilometer of coastline is enclosed by that isobath in the southern Canadian Beaufort than in the Alaskan Beaufort.

- The average position of the landfast ice/shear zone boundary is at a greater distance from shore east of the Mackenzie Delta than in the Alaskan Beaufort.

- There is more open water (year-round) in the southern Canadian Beaufort, especially east of the Mackenzie Delta, than in the Alaskan Beaufort.

- Storm surges and ice rafting are less frequent in the southern Canadian Beaufort because less fetch is available.

The general implication of these contrasts is that within the area of exploration interest in the southern Canadian Beaufort, artificial soil islands have been the favored drilling structure. In the Alaskan Beaufort, however, especially in the eastern section, the closer approach of the shear ice zone and 20 m (60-foot) isobath to the shore limits the application of artificial soil islands and ice islands.

The regional bathymetric and ice contrasts that exist in the Alaskan Beaufort should also be considered in the evaluation of the technological options for offshore drilling. A general observation is that a larger area of the continental shelf lies within the landfast ice zone and 20 m (60-foot) isobath to the west of Prudhoe Bay than to the east. These factors will especially restrict use of artificial soil and ice islands in eastern section of the Alaskan Beaufort.

With respect to the Beaufort Sea Federal OCS lease sale area, however, most of the area within the 10 m (30-foot) isobath and some within the 20 m

(60-foot) isobath lie in the landfast ice zone so both artificial soil islands and ice islands are feasible. Consequently, water depth, environmental concerns or other factors may be the ultimate selection criteria.

There is an east to west contrast in bathymetry in the American Beaufort which will be important in the selection of offshore drilling structures. East of Prudhoe Bay the 20m (60-foot) isobath lies 18 km (11 miles) offshore at Camden Bay whereas west of Prudhoe this distance increases to a maximum of 72 km (45 miles) off Harrison Bay. The implications of this contrast are that, other factors being equal, gravel or sand islands could be utilized over a larger area west of Prudhoe Bay than to the east. The shortage of sand and gravel on land and possibly offshore west of Colville River, however, could negate this factor.

1.3.2.3 Stage of Petroleum Development

One option for permanent production structures within the landfast ice zone is an artificial soil island suitably protected for an extended lifespan. Such islands may be 3 hectares (7 acres) or more in area and may be linked, where feasible, by causeways to the mainland or other production platforms. Such a production platform may be a modified and enlarged exploratory island. Temporary exploratory islands that have been abandoned may be utilized as borrow sources for permanent production islands elsewhere (a recycling program). Gravity production platforms are probably more attractive economic options in deeper water, and may be the only option beyond the 20 m (60-foot) isobath.

Ice islands could also be utilized as permanent production platforms if appropriate measures (insulation, refrigeration, annual ice-thickening) are taken to minimize and/or replace summer ablation losses.

1.3.2.4 Technology Available

The technology available for Beaufort OCS offshore operations will in part depend upon the scheduling of the lease sale. As indicated in Table I-2, the systems that have been proven to date are artificial soil islands, thickened ice platforms, sunken barges and ice-strengthened drillships. In the conceptual stage are existing technologies, such as semi-submersible rigs, jack-up rigs and gravity platforms, which will have to be modified or adapted to the rigors of the Arctic environment, in particular with respect to ice loading and ice scour. All of these systems will require certain design lead, testing and construction time (see Table I-2), which have to be evaluated within the framework of the lease sale schedule.

Experience gained in offshore operations in the southern Beaufort Sea of Canada will no doubt play an important role in selection of the technological options to be considered for offshore operations in the American section of the Beaufort Sea. This is because:

- Environmental conditions are similar; and
- Offshore activites are several years advanced of proposed American leasing schedules, and new equip- or technologies will have been field tested at this time by the Canadians.

TABLE 1-2

RE DRILLING STRUCTURE DEVELOPMENT TIMETABLE FOR ICE-RESISTANT STRUCTURES

Type of Structure	State of the Art (Proven in Use)	Technology Available	Prototype Design, Construction, Evaluation and Mobilization Time	Design Lead Time	Construction Time	Transport Time (Open Water Season)	Average Time to Utilization
Temporary							
Gravel	Yes			2 Mos.	2 Mos.		4 Mos.
Ice	Yes			2 Mos.	2 Mos.		4 Mos.
Movable							
Barge	Yes			2 Mos.	2 Mos.	2 Mos.	6 Mos.
Jack-up	Conceptual	Yes	2 Yrs.	6 Mos.	1 Yr.	2-4 Mos.	45 Mos.
Semi-submersible	Conceptual	Yes	2 Yrs.	6 Mos.	1 Yr.	2-4 Mos.	45 Mos.
Drill Ship	Yes	Yes		1 Yr.	1 Yr.	2-3 Mos.	27 Mos.
Fixed							
Protected Gravel	Yes*	Yes	1 Yr.	2 Mos.	6 Mos.		20 Mos.
Gravity Platform	Conceptual	Yes	2 Yrs.	1 Yr.	1 Yr.	2-4 Mos.	51 Mos.

*Only in shorefast ice.

: E.S. Clarke, 1976.

1.3.2.5 Logistics

Logistical considerations will have to be taken into account in the selection of offshore structures. Floating systems such as drillships and semi-submersible rigs not only have long mobilization periods (assuming transportation by sea from the lower 48), but also have a short working season (2-1/2 to 3 months) that results in very high standby costs during the winter. Locally constructed gravel islands do not have this problem and can be constructed and operated during either the winter or summer season. Artificial ice islands are the most logistically attractive exploratory platforms for the landfast ice zone, since they can be constructed with local materials (sea water) and a minimal construction spread.

At this time it is difficult to speculate on the types and numbers of gravity platforms or other non-locally-constructed drilling systems that may be utilized and where they might be constructed. The actual time to utilization as shown in Table 1-2 includes much prefabrication time before reaching the Arctic zone. Among the many factors to be considered, are developments in other previously-leased Alaskan OCS areas, such as the Gulf of Alaska. Discovery of economic oil and gas reserves in that area may lead to a local concrete production platform fabrication industry which may subsequently serve other Alaskan OCS areas including the Beaufort Sea.

1.3.2.6 Costs

There is little available data on the costs of the various offshore systems discussed herein. Selection of artificial islands for the southern

Beaufort Sea in Canada was in part based upon the low capital investment costs of man-made islands compared to other offshore structures. A figure of $11 million has been given for construction of the artificial island Netserk B-44 located in 4.5 m (15 feet) of water in the southern Beaufort Sea (Filey, 1975).

Helca N-52 offshore well [drilled in 128 m (421 feet) of water] in the Canadian Arctic islands costs $2 million, which included about $0.5 million for construction of the ice platform and $1.5 million for drilling the well (Baudais, Masterson and Watts, 1976).

Construction of an ice island to serve as a platform for an exploratory well is estimated at between $2.5 million and $5 million (Dames & Moore, 1975; Fitch and Jones, 1974). No figures are available for Union Oil's ice islands. There is little doubt that ice islands represent the most viable economic option, especially in areas where gravel or sand can not be obtained.

A major cost factor in the construction of artificial soil islands will be haul distances from the borrow sources to the island site and whether that source is onshore or offshore. It has been projected here that artificial island costs in the U.S. Beaufort will exceed those experienced in the Canadian experience, in part because of the more stringent environmental protection measures that may be imposed on dredging operations.

1.3.2.7 Environmental Impacts

The environmental impacts of the various offshore drilling structures, their construction and operation may have to be taken into consideration in the selection of such structures.

Particular attention may have to be given to the problems of borrow extraction, as well as dredging and related siltation problems, that are involved with the construction of artificial soil islands. State and federal regulations pertaining to borrow extraction, both offshore and onshore, will be a major determinant in the selection of gravel islands.

Other environmental concerns, particularly those associated with drilling schedules (summer or winter) and potential oil spills, will also have to be evaluated. Moreover, potential environmental impacts concerning the onshore facilities and equipment used to service the offshore platforms will also have to be evaluated.

Finally, the safety aspects of the operation of different types of offshore structures will have to be considered.

1.3.2.8 Resource Availability

Each of the offshore drilling systems described above have resource and service requirements which are quite apart from those associated with the drill rig and well.

Floating structures will be fabricated in the lower 48 or overseas. In contrast, artificial islands are constructed on site with locally available construction materials.

A major resource consideration is the availability of offshore and onshore borrow for construction of artificial islands (see Section 1.5.2.1).

Gravel and sand are important construction materials which are in short supply in some areas of the North Slope and Beaufort Sea, notably west of the Colville River (onshore and offshore). The availability of this resource, therefore, will be a major determinant of the type, location or numbers of offshore platforms.

Quarry stone (from the Brooks Range) or man-made armor (tetrahedrons) may be required in large quantities to provide protection for permanent artificial production islands. Consideration will have to be given to the availability of this resource.

1.3.3 Other Technology Options

1.3.3.1 Directional Drilling

Directional drilling from land (mainland or offshore barrier islands) to reach targets in a Federal OCS lease sale area (i.e. three miles or more offshore) is an alternative with probably limited application. Among the factors to be considered in evaluating the viability of directional drilling are the depth of the target, horizontal distance to the target, total length of the hole and the average angle of deviation of the well.

Assuming that a 3,050 m (10,000-foot) deep target located in the federal offshore lands could be drilled from shore by a well with an envelope angle of 56°, it would require a total length of 5,455 m (17,900 feet). In this report an average formation depth of 3,050 m (10,000 feet) drilled by a directional well of 50° with an average length of 4,100 m (13,500 feet) is specified (see Section 2.3.5.1). As the drilling angle increases, the total length of the well increases (as does the drilling time), although the area that can be drilled from a single location also increases.

Depending upon the maximum directional drilling angle (for a given horizontal distance to a target), there is minimum depth above which targets can not be reached without changing the drilling location (i.e. there is an envelope defined for any given drilling angle). For a given drilling angle the area (or cone) that can be reached by directional drilling increases with the depth of the target.

Although a maximum deviation envelope of 50° is cited in this report (see Section 2.3.5.1) as the typical maximum of directional drilling (see also Arthur D. Little, Inc., 1976), the maximum deflection from vertical developed in the bottom of the well is actually greater. An ultra high-angle well reaching 82° (i.e., nearly horizontal) has been reported (Eberts and Barnett, 1976); however, the depth of the well was 1,325 m (4,350 feet) which required a 3,750 m (12,300-foot) total length, such that the average deviation was 68° from the mudline. A comparable directional well (68°) required to reach a 3,050 m (10,000-foot) offshore target would have a total length of 9,100 m (30,000 feet) which would prove prohibitively expensive. Thus the total length of the hole and average angle of directional drilling essentially present economic limits on directional drilling.

Overall, if there was a significant oil deposit (requiring several wells) which was adjacent to the original platform location, it would be more economic to put in a new platform for the wells than to do high angle drilling. However, for a known deposit which would support one expensive well, but not several, it would be preferable to pay the directional drilling costs.

For exploratory drilling in the Beaufort Sea, there is little incentive for directional drilling from land, or, for that matter, directional drilling from an ice island. The cost of an exceptionally long directional well would probably outweigh the cost of installation of an ice island or a second ice island at a new location. Furthermore, the increased drilling time with respect to the short-life span of an ice island should be noted. Another consideration is that high angle wells are not recommended in poorly-known geologic provinces, i.e. during the early exploratory efforts in frontier areas. On the other hand, production drilling, with up to 40 wells per platform, will commonly employ deviated wells.

1.3.3.2 Offshore Tunneling and Chamber Systems

An alternative to offshore platforms, subsea pipelines and marine terminals required to produce an offshore oil and gas field has been proposed (Lewis, Green and McDonald, 1977). The offshore tunneling and chamber system (OTACS) would consist of a complete drilling and production system beneath the sea comprising two tunnels, a service tunnel (rail lines, access to drilling chambers, pipelines) and one for airflow, which would be linked by cross-over ducts. The adit and surface complex would be located near the shoreline. To produce a reservior covering 77 square kilometers (30 square miles) offshore in an area such as Prudhoe Bay, it is estimated that a 16 km (lO-mile-long) tunnel punctuated with drilling chambers every 2 km (1.25 miles) would be required. Directional drilling from each of eight chambers with 12 wells per chamber would be sufficient to access the 77 square kilometer (30-square mile) reservior. Two depths were considered for OTACS: a shallow 300 m (1 ,000-foot) level and a deep 600 m (2,000-foot) level.

The advantages of such a tunneling system over more conventional offshore development are cited to be:

- Dryland drilling technology and normal production systems are readily transferable to the tunnel.
- Logistical problems and delays due to weather are minimized.
- The working environment is protected from the harsh Arctic climate.
- The oil spill problem may be less serious and more easily dealt with underground than in the Arctic Ocean, especially under ice.
- Arctic marine structures and ocean-floor pipelines are eliminated.
- Drilling conditions are more predictable and can continue year-round.

The authors acknowledge the need for strict safety requirements in OTACS but do not foresee any insurmountable problems. They also note that offshore tunneling is not a new technology since there are many examples worldwide of subsea mines and transportation tunnels. However, venting and fume control may be a more serious obstacle for hydrocarbon exploration than envisioned by the innovators of the tunneling system. Well blowouts may also pose serious problems and prove no less difficult to control than aboveground facilities. Economics will probably be the most important aspect of the feasibility of OTACS petroleum production. For the complex described above, a total capital cost of $399 million is cited. This figure includes tunnel construction, power generation facilities, ventilation, well drilling and installation and safety equipment. Nevertheless, the capital costs of OTACS, though obviously tentative, far exceed the individual field development costs (including pipelines) that are estimated in this report for the various petroleum development scenarios.

1.3.4 Oil Field Operations

1.3.4.1 Oil Characteristics

The characteristics assumed for the oil produced are based upon the North Slope oil already found, an analysis of which is given in Table 1-3. The effects of alternative assumptions on oil characteristics are discussed below.

1.3.4.1.1 Oil Viscosity and Reservoir Characteristics

The gravity of oil, its composition in light and heavy fractions, and its viscosity at a given temperature are correlated. Below a certain temperature, called the pour point, it will gel and not flow. Crudes of very low gravity 50 to 150 API may not flow from the reservoir unless they are warmed or diluted with a solvent. Crudes of very high gravity (350 to 450 API) flow readily from the reservoir, but are high in lighter fractions

TABLE 1-3

ANALYSIS OF A REPRESENTATIVE NORTH SLOPE CRUDE

TBP Cut °F	Gravity ° API	Whole Crude vol. %	Gasoline Cut 97-296°F TBP vol. %	Lt. Diesel Cut 296-538°F TBP vol. %	Resid. 538°F + Vol. %
C_2	----	0.1	-----	----	----
C_3	----	0.4	-----	----	----
iC_4		0.2	-----	----	----
nC_4	----	0.7	-----	----	----
iC_5	----	0.5	-----	----	----
nC_5	----	0.7	-----	----	----
97-178	71.6	1.5	15.62	----	----
178-214	59.7	2.1	21.89	----	----
214-242	55.0	2.0	20.83	----	----
242-270	53.8	2.0	20.83	----	----
270-296	49.6	2.0	20.83	----	----
296-313	49.6	1.0	-----	4.78	----
313-342	47.3	2.0	-----	9.57	----
342-366	46.0	1.0	-----	9.09	----
366-395	44.0	2.0	-----	9.57	----
394-415	38.6	2.0	-----	9.57	----
415-438	38.8	2.0	-----	9.57	----
438-461	37.2	2.0	-----	9.57	----
461-479	35.4	2.0	-----	9.57	----
479-501	33.9	2.0	-----	9.57	----
501-518	33.1	2.0	-----	9.57	----
518-538	32.2	2.0	-----	9.57	----
538-557	31.8	2.0	-----	----	2.99
557-578	31.6	2.0	-----	----	2.99
578-594	30.7	2.1	-----	----	3.14
594-610	29.6	2.0	-----	----	2.99
610-632	28.0	2.0	-----	----	2.99
632-650	26.9	1.8	-----	----	2.69
650 +	14.6	55.0	-----	----	82.21
		100.0	100.0	100.0	100.00

	Whole Crude	Gasoline Cut	Lt. Diesel Cut	Resid.
Gravity, °API	25.7	57.4	38.9	16.8
ASTM distillation				
Initial boiling point, °F	-----	131	332	-----
10%	-----	186	359	-----
50%	-----	222	427	-----
90%	-----	267	494	-----
End point	-----	315	525	-----
Sulfur, wt. %	1.12	0.03	0.15	1.45
Con Carbon	5.99	----	----	----
RVP	4.8	3.1	0.3	0.1
BS & W, Vol. %	0.6	----	----	----
Vis., SUS at 0°F	----	29.6(1.08 cs)	----	----
at 32°F	----	----	26.6(3.19 cs)	----
at 70°F	182.5	.742 cs	----	8608
at 100°F	94.1	----	31.4(1.58 cs)	2309
at 210°F	----	----	----	114.5
Pour point, °F Upper	+20	----	-60	+55
Lower	-lo	----	----	+50
Water by distillation, vol. %	1.5	----	----	----
Fraction of crude, vol. %	100	9.6	20.9	66.9

Note : "Characteristics of World Crude oils", 1975. Petroleum Pub. Co. (Oil & Gas Journal), 1975, Tulsa, Oklahoma.

which will tend to vaporize or evaporate in the atmosphere and in transport. The percentage of recovery of the light gravity oils inplace is higher because the oil can migrate from the reservoir zones more readily. However, for reservoirs with good permeability, and formation temperatures well above the pour point of the oil, the effects of viscosity on the oil recovery are not expected to be significant.

1.3.4.1.2 Gas, Water, and Impurities

The reservoir projected as typical for Beaufort Sea OCS is a replication of the Prudhoe Bay major reservoir with respect to gas, water and impurities. This consists of a geologic trap -capping of the porous sand zones to create a reservoir in which oil, gas, and water may migrate. The reservoir is layered as a result of the densities of the fluids with a gas cap at the top, an oil sand layer below it, and a water barrier below. Some gas will be dissolved in the oil, and some oil vapors will be present in the gas. The ratio of gas to oil in the reserves (recoverable resources) is estimated to average 2,500 mcf of gas at normal atmospheric pressure for each barrel of oil. As the gas, oil, or both are produced from the reservoir, they may contain impurities of water, hydrogen sulfile gas (which may be present in the gas or oil), and sand grains from the reservoir sands.

The water is saline and is generally benign to the equipment. However, one of the preferred ways of disposing of it is to return it to the underground formation. Thus it may be separated from the oil offshore at the platform. Alternatively, it may be treated onshore to reduce the oil trace content, and then discharged into the sea.

Sand in the fluid is abrasive, and is generally removed as quickly as practical. However, there is no indication that sanding may be a problem, but it also may be treated onshore if practical. Some trace sand content will remain in the oil until delivery to a refiner.

Hydrogen sulfide is corrosive to the equipment, and is also removed as quickly as practical. For artificial islands, with adequate space, it could be removed offshore. However, with adequate control techniques, it can also be carried onshore for treatment.

1.3.4.2 Lift and Reservoir Pressure Maintenance

Considerable pressure--greater than the weight of the fluid column--must exist or be exerted on the oil if it is to be lifted to the surface. Although this pressure may exist in the fluid initially, it may dissipate as oil is withdrawn unless (a) the underlying water layer can exert pressure by migrating upward or (b) the gas cap pressure can be maintained. Oil is nearly incompressible, and a small change in volume will produce large pressure changes. The opposite is true of compressed gas, which can undergo some withdrawals of its volume and still maintain considerable pressure.

Because of the critical shortage of U.S. natural gas, it should be assumed that gas production from the cap will be desired. An alternative method to produce lift is to increase the underlying water pressure in the formation by injection of water. Direct lift of the oil by submersible pump is possible, but is not effective in driving the oil to the well. A water drive below or behind the oil forces it through the reservoir, and has been considered the most likely lift mechanism for the field.

Maintenance of lift by water pumping requires energy, a water treatment plant, pumping stations, and injection wells. Seawater may be used, and simple filtration may be sufficient treatment.

1.3.4.3 Well Technology

1 .3.4.3.1 Drilling

A typical oil well drill consists of a bit which presents a cutting face or gear teeth, diamond bits, against the rock or sedimentary formation. The bit is guided into the earth at the end of the rotating pipe - the drill stem. The torque for rotation is applied at the drilling platform, so that as that well proceeds deeper into the rock, the drill stem must be lengthened. At intervals, drilling is halted, and well casing pipe is placed in the well. The drilling derrick over the platform is used for hoisting sections of pipe and drill stem. In Arctic cold, the derrick may be enclosed or partially enclosed to protect the workers and equipment.

Every change of operations, such as cementing, changing drill bits, placing casing, etc. requires the drill stem to be withdrawn from the hole, section by section. As the hole deepens the time devoted to lifting and reinserting the drill becomes a primary factor in drilling time. Operational failures, such as a broken drill stem, may increase drilling time significantly. Typical well drilling time may be 45 to 60 days for wells 7,000 to 10,000 feet in depth in the Arctic.

Mud flow is an important control factor for oil drilling. Normal litho-static pressures--the weight of the earth above a deeper layer of rock--will reach several thousand pounds per square inch. This pressure is balanced by the weight of a column of drilling fluid or mud in the well--circulated down the drill stem, out the bit, and returning up to the surface around the drill stem. The drill mud provides pressure control, lubricates the cutting bit, and carries the cut rock up to the surface. At the surface, the cuttings are washed out and discarded and the mud is recirculated. The mud may be dumped at the end of drilling, where regulations permit.

Uncontrolled discharge of high pressure formation fluids or gases up the well is a blowout. The mud control may not be able to restrain a surge when unexpected high pressure pockets are penetrated. Blowout control valves are installed at the wellhead in case mud control fails--including an exploding blind ram which seals off the casing if all other valves fail. High and low level alarms on the mud flow warn if the mud fails to return--indicating a void space has been encountered--or if mud returns faster than the injection rate.

Drilling down time due to well control problems has been projected not to be a critical factor in the Beaufort OCS. In this regard, it should be noted that an individual blowout or problem well would not affect the average cost estimates for the wells in a set of oil fields, but could create adverse environmental problems with widespread notice.

1 .3.4.3.2 Underwater Drilling

For a well drilled on land, the drilling platform is immediately over the wellhead, and virtually a part of it, until the well is completed. For underwater drilling, the well head is placed on the bottom, and the drilling platform above water--sometimes several thousand feet, as has been accomplished in geotechnical coring of the ocean bottom. The drilling platform may be a stable platform standing on the ocean bottom, or it may be floating. Ocean drilling at the present time from a fixed platform is nearly equivalent to onshore drilling--except for the considerable expense of the platform and logistics of supplying the platform over water. Drilling from a floating platform is more difficult. Allowance for deflection of the platform requires some flexing of the drill stem above the wellhead. If wave roughness exceeds certain “window” conditions, the drill stem must be pulled out, the wellhead shut in, and drilling suspended until calmer conditions prevail. The most significant portion of drilling costs are those which are time-related--the equipment and cost-greatly outweighing those which are derived from materials consumed. Thus non-drilling time during weather-caused interruption is nearly as costly as the drilling time. Well costs can be increased significantly by such down periods-as much as ninefold differences in some North Sea wells between calm and rough periods (A.D. Little, Inc., 1976).

In the Beaufort Sea within the 20 m (60-foot) isobath, stable platforms are expected--most likely of an artificial island form, constructed of gravel or ice, with and without concrete or steel skeletal reinforcement.

Wells may be directionally drilled from stable platforms at an angle of 45° to 50° with the vertical, so that a considerable area of formation may be covered from a single platform location with 65 hectare (160-acre) well spacing. The 45° cone permits 11 wells from a single point for a formation 1,500 m (5,000 feet) deep, 45 wells at 3,000m (10,000 feet) . A well may also be produced at more than one level throughout its life, if it penetrates multiple layers of oil sand.

1 .3.4.3.3 Well Control, Interruption, Restart

After a hole has been cut through some depth of rock, steel pipe is placed into the hole and cemented into place. The cement is forced into the void around the pipe under pressure, while the pipe above is sealed off by a pneumatic packing seal (above and below when a gap between two pipe sizes is being cemented). A typical casing program is given in Section 2.3.5.1. Minimum casing programs may be specified by OCS regulations for particular areas. The steel casing and cement prevent high pressure fluids from lower zones from fracturing and penetrating upper zones. Full casing has been used in OCS wells since a blowout occurred in the Santa Barbara Channel in 1969.

The role of mud for pressure control in drilling is important. The mud circulation may also reveal some gas bubbles or oily cuttings, sometimes a warning that high pressures may be encountered soon. After drilling in a deep well has been stopped, pressure in the well column may increase. Reentry of a well is especially a hazardous point in drilling, but is done routinely. For underwater wells, reentry techniques have evolved using guiding pins on a wellhead template on the ocean floor.

Control of a completed well is maintained by subsurface valves, the valves in the wellhead, and by permanent chokes--nozzles restricting the flow in the production casing outlet.

1 .3.4.3.4 Well Service and Maintenance

During the life of the well, it is sometimes necessary to place well tools or chemicals into the well to remove sand, corrosion, increase perforations available for oil to enter the casing, repair cementing, etc. These procedures may be performed from workover rig, similar to a drilling rig but with the tools downhole generally operated by wireline instead of a rotating drill stem.

Sometimes additional wells may be placed in the field, reducing the well spacing at certain locations to improve recovery. In a water flood draining of the field, additional wells may be drilled for better pressure pattern in the reservoir drive.

1.3.4.4 Well Specifications

In this report the specifications of a typical well, equipment and materials are presented in Section 2.3.5.1. The specifications are based upon the assumption that most offshore development and production wells in the Beaufort Sea will be directionally drilled to an average vertical depth of 3,000 m (10,000 feet) (assumed from the average depth of Prudhoe Bay wells). Such a directional well drilled approximately 50° would have an average length of 4,100 m (13,500 feet).

To maintain the integrity of the hole in permafrost, many of British Petroleum's production wells at Prudhoe Bay have been equipped with about 600 m (2,000 feet) of thermocasing (Oil and Gas Journal, 1976). Subsequent tests have indicated that thermocasing is not required if the correct grade of 13-1/8 inch casing is used. However, thermocasing has continued to be used for the top 45 to 60 m (150 to 200 feet) of the hole to prevent subsidence of the surface soil and thawing of permafrost. To insulate the permafrost from the hot crude oil, Atlantic Richfield at Prudhoe Bay has utilized a specially developed non-freezing fluid circulated into the annulus of the 9-5/8 inch casing through the permafrost interval to about 550 m (1,800 feet). Sun Oil utilized a refrigerated surface string on its first two exploratory wells in the southern Beaufort Sea (Brown, 1976).

On a soil or ice island with production wells closely spaced, thermocasing or refrigeration may be necessary to avoid surface settlement as a result of the degradation of the permafrost. This would only be necessary if the soils were ice-rich and potentially (thaw) unstable. At most locations offshore the permafrost is unbended (non-ice-rich) and/or a thick unfrozen layer overlies the permafrost and such measures would not generally be required.

1.3.5 Oil Processing Technology

The oil produced comes to the surface as a mixture of gas and liquid--with gas dissolved in the liquid, condensable liquid dissolved in the gas, and the liquid composed of an oil-water emulsion with impurities. The gas must be separated from the fluids before entering a pipeline. If more than a limited amount of gas is in the line, the mixture will not flow smoothly or be easily pressure regulated.

1.3.5.1 Gas Processing

The fluid-gas mixtures produced can be transported by pipeline a few miles to a processing point. At the processing point, gas is evolved from the heat treating of the fluid to break the oil-water emulsion. This gas is collected and returned to the primary gas stream.

The gas collected is mostly methane, but will contain valuable amounts of heavier, liquefiable gases, as well as condensable light oil fractions. The gas processing first removes any entrained liquid droplets and mists. Other liquid products then are absorbed from the stream in counter-flowing absorption towers. Easily condensed fractions may be trapped out in compression. If the gas is to be returned to the reservoir to maintain field pressure, the main purpose in stripping the gas is to recover these natural gas liquids, which may be used as petrochemical feedstock. If the gas is for direct pipeline sale, as it may be if delivery across Canada were involved, then conditioning of the gas may be contractually required. Liquid droplet condensation in pumping compressors must be avoided. If the gas is to pass through a liquefaction plant, as was proposed with a trans-Alaska gas pipeline, final conditioning of the gas may be left to the shore-side plant. Conditioning would then be primarily aimed at pipeline transmission requirements.

1 .3.5.2 Sulfide Removal

Both the oil and gas may contain hydrogen sulfide gas as an impurity. This compound is toxic and corrosive, and is removed from the flow as quickly as practicable. If the gas is to be reinfected, corrosion protection from hydrogen sulfide may be accomplished adequately by DEW point control. Typical removal is accomplished by absorbing the sulfide into contacting amines. The amines are then regenerated by heat, and the sulfide can be reduced to sulfur or sulfite liquor for by-product disposal. Some trace hydrogen sulfide will be emitted--"tailed"--into the atmosphere, where it may create a detectable odor.

Hydrogen sulfide is a problem impurity at levels of a few parts per million (ppm), and may be present at up to 10-20 ppm. It is not a significant part of the total sulfur content of the oil. Chemitally bound sulfur is typically 0.5 to 2.5 percent of the oil by weight but is passed onto the refinery without any processing in the field.

1.3.5.3 Sand and Water Removal

Sand and water removal, after the breakdown of the oil-water emulsion, is performed by gravity settling as the mixture passes baffles and sand traps. The practical limit of oil separation from formation water on land may be about 5 ppm. On platforms, the practical limit may be about 35-50 ppm of oil in water. Since use of water to maintain pressure in the field is likely, it has been assumed that formation water would be reinfected.

Formation water in the oil is of less concern than removal of oil from water since the oil may be exposed to contamination by water during tanker shipment (from the ballast waters). Moreover, pipeline specifications permit a small amount of water and solids in the line.

1.3.6 Pipeline Design

1.3.6.1 Introduction

This section briefly describes various environmental and geotechnical problems associated with pipeline construction in the Arctic. To date, no offshore pipelines have been laid in the Arctic and there is little published literature related to potential problems. There is, of course, a wealth of data on onshore pipelines, both oil and gas, in the Arctic. Future design and construction of pipelines related to OCS development will no doubt incorporate the experience of Alyeska and the proposed Northwest (Alcan) pipeline.

With respect to OCS development in the Beaufort Sea a series of offshore gathering pipelines linking offshore fields or platforms with the shore can be envisaged. These would connect with an onshore trunk line that would transport the oil or gas to the Alyeska, or proposed Alcan pipeline. The economic analysis in this report (Chapter III) indicates that there are insufficient oil and gas reserves (based on current U.S.G.S. estimates) in the Alaskan Beaufort Sea to justify a new trans-Alaska oil or gas pipeline. Another Prudhoe-size discovery is unlikely. Consequently, Beaufort Sea oil or gas might have to be transported by utilizing spare capacity on existing pipelines.

Pipeline specifications related to the petroleum development scenarios are presented in a series of tables in Chapter II. These tables present data on pipeline mileages (from western, central and eastern reserves to a Prudhoe Bay interconnection), as well as pipeline diameters, gravel requirements, and other pertinent factors.

1.3.6.2 Offshore Pipelines

Although several offshore drilling systems have been tested in the fast-ice nearshore zone of the Beaufort Sea, to date no pipelines have been laid and operated on or beneath the Arctic sea floor.

General pipeline design and planning in the Beaufort Sea will have to consider such factors as:

- Ice conditions, particularly ice scour;
- The extent, thickness, depth, ice-content and temperature of subsea permafrost;
- The geotechnical characteristics of bottom sediments;
- Currents and sediment transport;
- Bathymetry; and
- Biological concerns.

A major design and construction consideration for offshore pipelines will be the location, depth and frequency of ice gouging or scour. Ice movement resulting in gouging of the shelf sediments is concentrated in the dynamic stamuhki zone located in an irregular band between the 10 m (30 feet) and 20 m (60 feet) isobaths, but extending seaward as far as the 45 m (150-foot) isobath.

A description of ice scour is presented in Section 1.2.1 and summarized in Table I-1. Pipelines located beneath the Beaufort Sea will have to be buried to an appropriate depth dictated by ice scour risk analysis. Consideration of the scour problem indicates that much of the possible federal lease area lies shoreward of the stamuhki zone and that gouges greater than 2 m (6 feet) are rare. The available scour data indicates that in water depths of less than 6 m (20 feet) a burial depth of 1 m (3 feet) may be sufficient, and in the mid-shelf zone with water depths from 7 m (20 feet) to 45 m (150 feet), 2 m (6 feet) may be sufficient (see Section 1.2.1). Consequently, ice scour does not present an insurmountable problem for construction and operation of offshore pipelines.

Closer to shore in waters less than 7 m (20 feet) deep, gravel causeways may be feasible to carry pipelines. The causeway concept would also overcome the potential, though localized, thaw stability problems of permafrost in the sea floor within a mile or two of the coastline. At greater distances from the shore, any subsea permafrost would probably be at depths sufficient to minimize thawing from hot oil pipeline, and therefore, would not present problems to the integrity of the line.

An alternative to conventional trunk pipelines is a series of small diameter (12 to 14 inches) pipelines which can be transported and laid from spools on a barge. Several 12-inch lines laid parallel in the same trench could replace a single larger diameter trunk line. This could avoid completely shutting down a field if a problem developed in a single line.

Natural wave and thermal erosion of coastal bluffs of the Beaufort Sea is very rapid in some areas (Lewellen, 1970). Therefore, another important design consideration will be protection of the pipeline from ice and shoreline erosion at pipeline landfalls.

To date, Polar Gas is the only company planning offshore Arctic pipelines to be constructed through sea ice. Polar Gas has proposed to build a large diameter gas pipeline from reserves in the Arctic islands to the eastern Canadian provinces (O'Donnell, 1976a & b). The proposed routes traverse several deep inter-island channels with water depths up to 300 m (1,000 feet). Although the physical conditions, particularly bathymetry of the Arctic island channels, is dissimilar from that of the Alaskan Beaufort Sea, Polar Gas experience on pipelaying from sea ice will prove valuable to future Beaufort Sea operations. Initial concerns on iceberg scour in the channels have been eased by research although in foreshore areas and water depths of up to 45 m (150 feet) protection from scour will be required (Kaustinen, 1976). In these situations Polar Gas proposes to utilize tunnels to carry the pipeline in preference to trenching.

In the shallow-water landfast ice zone areas of the Alaskan Beaufort Sea, winter pipelaying through the ice may be feasible as a practical and economic alternative to summer construction using conventional offshore techniques. Where the fast ice is grounded no thickening of the ice would be required. Offshore pipelining, though traditionally much more expensive than onshore construction, may prove to be more competitive in this part of the Arctic than elsewhere. Winter offshore pipelining in the landfast zone may prove to be sufficiently competitive to make longer offshore trunk routings preferable to onshore routes.

Overall, the advantages of offshore routings and offshore winter construction include:

- No river crossings would be required (these are geotechnically expensive and environmentally sensitive).
- No gravel work pad or haul roads would be required.
- The winter construction season on ice is longer than the open water season.
- Winter construction on ice will avoid conflict with major migrations of waterfowl, fish and marine mammals which occur in summer.
- An elevated hot oil pipeline is not required.

1.3.6.3 Onshore

Onshore hot oil pipelines would probably be aboveground (cf. Alyeska) except in areas of thaw stable soils and at some major river crossings. It can be assumed that construction and operational experience gained by construction of the Alyeska pipeline, including environmental data, will influence the design and routing of subsequent North Slope pipelines. Similarly, the Alcan experience will no doubt be applied to the design and construction of onshore gas pipelines which would probably be below ground.

1.4 OIL SPILLS AND THE BEAUFORT SEA ENVIRONMENT

1.4.1 Introduction

The ice cover of the Beaufort Sea is highly heterogeneous, and any consideration of oil impact must include prior knowledge of the character and interaction of sea ice, not only in the Beaufort Sea, but in the Arctic Ocean as well. Classification of topography and morphology, as well as ice dynamics, are fundamental to understanding the problems associated with oil blowout, containment, and cleanup under and on the sea ice.

1.4.2 Ice Zones and Types

1.4.2.1 Fast Ice Zone

Fast ice (also called landfast or shorefast ice) develops along the southern coast of the Beaufort Sea and may extend from the beach to approximately the 20 M (60-foot) isobath.

Nearshore fast ice, or the inner belt, begins to develop during early October growing in thickness to about 2 m (6 feet) by late March. For the most part, it rests on the shallow sea bottom and normally gives the appearance of a smooth, level sheet with occasional small hummocky areas. It is nearly but not completely static throughout the winter, and it lasts until late June.

A blowout in the inner belt will most likely spread outward from the blowout site, forming a coherent slick across the bottom surface of the ice.

The only vent will be immediately above the blowout site, but only if the inital gas and oil plume is forceful enough that the ice yields to fracture is hot oil or continues to flow for a sufficient period of time to cause melting. Rarely will there be meso-form features (depressions or projections) to constrain spreading of accidentally spilled oil, nor will there be leads of open cracks.

The outer fast ice belt is topographically characterized by fields of ridges and hummocks, although the ice itself remains nearly stationary. During the fall freezeup, areas of rafted rubble or hummocky ice are generated in the outer belt by pressure from the seasonal and polar pack that pushes southward on the young (first-year), fast ice.

In the outer belt areas, the relatively rough bottom surface of the ice sheet will tend to consolidate and contain oil in pools and pockets.

1.4.2.2 Seasonal Pack Ice Zone

The seasonal pack ice zone (also called the shear zone or transition zone), extends northward 95 km (60) to 160 km (100 miles) from the coast to the toe of the continental shelf. It is characterized by variable ice types and conditions and is always in motion as it twists and compacts, and opens and closes. In the fall, the zone comes under the influence of the polar pack ice. This is caused by a gradual steepening of regional surface barometric gradients which result in an onshore wind pattern. Severe onshore fall storms will modify significantly the overall character of any first-year ice cover which might form, and it may introduce ice island fragments and multi-year flows floating off the periphery (slippage region) of the polar pack. Although seasonal pack ice will become more compact as winter intensifies and, therefore, more resistant to penetration by the polar pack, it will vary considerably from season-to-season and from year-to-year. It is by far the most dynamic of the three ice zones.

Oil caught under or within the seasonal pack may travel 1.9 to 4.0 km (1.2 to 2.5 miles) or more in any 24-hour period. A maximum shift of 48 km (30 miles) in one day has been recorded. As a consequence, containing oil to the immediate vicinity of a spill or blowout until cleanup operations can begin will be extremely difficult.

1.4.2.3 Polar Pack Ice Zone

Unlike the fast ice and seasonal pack ice zones, the polar pack ice zone is distinguished by its nearly permanent assortment of all sea ice types and its consistent anticyclonic movement within the Pacific gyre. The zone of polar pack ice lies beyond the continental shelf for most of the year, behaving as a cohesive mass with slippage over a narrow region [about 50 km (30 miles)] at the boundaries.

Ice thickness will vary from first-year thin ice in leads and polynyas to multi-year flows 1.8 to 3.6 m (6 to 12 feet) thick (or more) to ice island fragments and pressure ridges which can reach 45 m (150 feet) or more in depth. The intensity of ridging will vary depending on the season, the area, and the year; generally it will be less severe in the southern Beaufort Sea than in the Arctic Basin, but it can vary considerably from year-to-year. Typical spatial density of ice ridges is reported to be in the range of 9 to 18 ridges per kilometer (15 to 30 per mile), their average heights about 3 m (10 feet), and the height ratio of keel to sail 3 to 1. Ridges can exceed 15 m (50 feet) in total thickness and, if caught in the zone of seasonal ice flow during late summer and early fall, may become grounded. Ridges have been observed as far in toward shore as the outer fast ice belt.

Oil contaminates travel to the polar pack ice, driven by winds and currents, as well as the ocean dynamics that move from the fast ice zone through the seasonal zone and into the polar pack.

1.4.3 Ice Structure, Morphology and Topography

For about 9 months of the year, the ice cover on the Beaufort Sea is nearly complete. However, leads, windows, and polynyas are nearly always present because of the effects of tides, winds, and currents.

Formation of sea ice is a refining process during which most ions foreign to pure water are rejected in the freezing process. When saline water freezes slowly, brine will be rejected from the ice and remain in the melt. However, this seldom occurs in nature because most often the freezing rate is too rapid for complete rejection. Thus the quantity of brine trapped between ice crystal boundaries and between ice platelets becomes a highly variable function of the freezing rate.

As the ice warms during spring melt, the presence of brine channels becomes important. It is at that time that brine drains downward under the influence of gravity and the less dense oil would then migrate upwards through brine channels and along crystal boundaries to the ice surface.

Oil in the shallow coastal waters of the Beaufort Sea [$\leq$ 60 m (200 feet)] will rise from its source on the sea bed to the ice-water interface in a conical plume with a half-angle of approximately 25 to 30 degrees. An oil and gas mixture, however, will rise as a conical plume initially and then become nearly cylindrical. The distance at which the conversion occurs will depend upon such variables as the ratio of oil to gas, blowout pressure, oil density, and any current or wave action which may be present. Experiments at depths greater than 60 m (200 feet) have not been attempted, thus any additional change in shape of the plume is unknown.

After being discharged, oil quickly breaks into small, nearly spherical particles which, depending upon gas flow, may rise at rates that vary from approximately 0.3 to 1 m/second (1 to 3 feet/second). At the ice-water interface, most crude oil will first coalesce to form sessile drops. In the process of spreading out, many of those drops will in turn coalesce and develop into rivulets which, for most crude oils, will spread at a radial velocity approaching 0.45 to 0.61 m/second (1.5 to 2 feet/second). Under an ice sheet that is flat, the rivulets will travel outward unimpeded until they meet the wave ring created by the ejection of gas and oil (primarily gas). Or if the underside of the ice surface is irregular the oil will tend to pool in concavities.

The topography of the bottom of an ice sheet is the most important factor in the containment of oil. However, ice movement that is generated by wind, current, tide and lateral forces resulting from the pressures of surrounding ice will also have a marked effect on the spreading and movement of oil.

The underside of an ice sheet approximately reflects its surface topography. Projections beneath the ice will usually indicate hummocks or ridges on the surface. Concavities along the under surface of the ice generally testify to snow-free ice surface above; convexities, on the other hand, may signify that a snow drift or dune is an insulating cover on the surface of the ice.

With respect to the petroleum development scenarios and potential oil spill problems, the following provides a summary of the environmental contrasts between Camden, Prudhoe and Smith bays.

Camden Bay

Fast Ice -- the inner belt (grounded ice zone) is very close to shore extending seaward only 52 to 200 m (170 to 650 feet). The eastern half of the bay from Collinson Pt. to Anderson Pt. is completely open to infringement by seasonal pack ice. On the other hand, the western half (Simpson Cove) is partially protected by a narrow spit stretching westward from Collinson Pt. and by the morphology of Kanganevik Pt. and the nearly 900 m (3,000-foot) extension of shallow bar stretching eastward. Thus the western half of Camden Bay is more protected from the dynamics of seasonal and polar pack ice forces (pressure ridging, bottom scouring, etc.) as well as storm waves and surge than is the eastern half. The northern limit of fast ice, including both inner and outer belts, extends out about 13.6 km (8.5 miles).

Prudhoe Bav

Fast Ice -- the inner belt (grounded ice zone) extends seaward about 1.6 km (1 mile) beyond Gull Island which lies near the mouth of the bay or a total of approximately 18 km (11 miles) from the beach at the farthest point inside the bay. Prudhoe Bay is well sheltered from all but the most adverse ice conditions by both nearshore and offshore barrier islands and because the coastal shelf remains very shallow, i.e., 6 m (20 feet) or less, off the mouth of the bay seaward for nearly 15 km (9 miles). These natural obstacles to ice forces, storm winds, waves and surges, in addition to the wide band of fast ice that forms each winter, provide a large measure of inherent protection. The northern limit of fast ice, both inner and outer belts, extends off Prudhoe Bay 24 to 29 km (15 to 18 miles).

Smith Bay

Fast Ice -- the inner belt (grounded ice zone) extends about 13 km (8 miles) from the coast of the mouth of the bay except for a small "re-entrant" or channel on the westernmost side. The bay is large encompassing an area of over 260 square kilometers (100 square miles). It is not sheltered from waves or winds, but it is shallow [generally less than 2 m (6 feet) deep] and therefore not subject to ingress by large multi-year ice flows which could create bottom scouring. The limit of fast ice, both inner and outer belts, extends northward for from 29 to 35 km (18 to 22 miles).

Spillage probabilities have been developed for the specific Beaufort Sea OCS scenarios under consideration, these are shown in Section 2.3.9 and include the likelihood of platform blowouts, platform spills and pipeline spills.

1.5 ENVIRONMENTAL CONSIDERATIONS

This section outlines some of the environmental conditions which may be affected by petroleum development in the Beaufort Sea area. These conditions include biologically sensitive areas; water and gravel resource locations, and subsistence resources. In addition, this section includes a discussion of federal and state land use regulations, and availability of ports and necessary infrastructure to support petroleum development.

Onshore and coastal zones extend from Wainwright on the west to the Canadian Border on the east. The coastal zone can be divided into two units, the East Arctic and the West Arctic which are separated by the Colville River. (See Figure 1, Location Map). Primary impacts within this zone will be associated with the construction of offshore pipe-lines, onshore staging areas, and onshore pipelines.

The purpose of this section is to describe the environmental context within which petroleum development will occur from the standpoint of potential effects of development on the environment. In addition, this section will include a basic overview of information for consideration of more detailed locational factors associated with each of the selected petroleum development scenarios. The discussion of biologically sensitive areas, resource areas, jurisdictional concerns and existing infrastructure does not represent an exhaustive analysis. Those issues will be covered as part of the Community and Regional Baseline Studies. Rather, this discussion is focused on identifying key conditions which will need to be considered in determining the location, timing and nature of petroleum development activities, in addition to the overriding concern of cost.

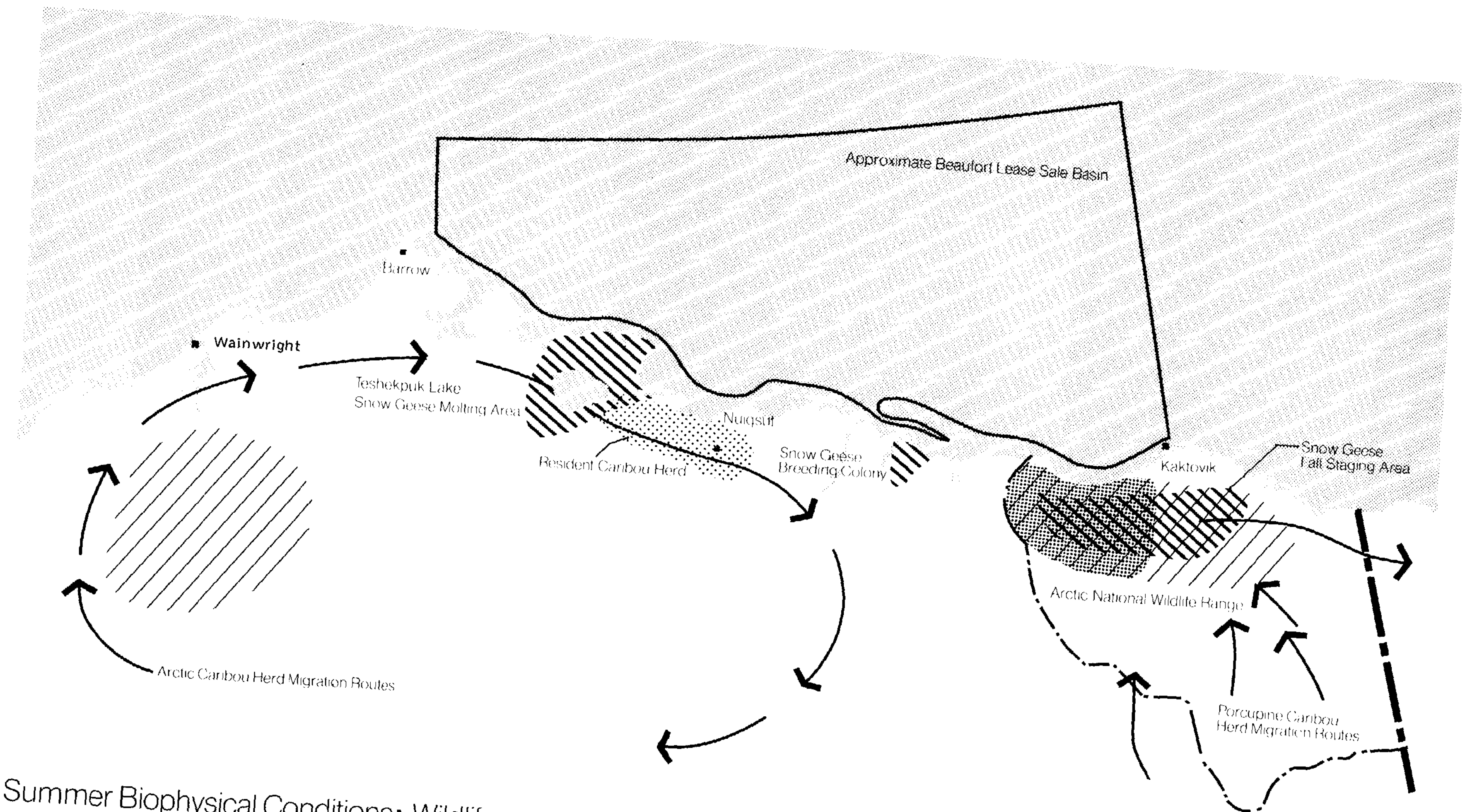
1.5.1 Natural Environmental Conditions

The Beaufort Sea area contains a variety of habitats which support both year-round and seasonal wildlife populations. The following section outline the variability of these potentially affected environmental factors.

1.5.1.1 Summer Marine Habitats

Summer marine and waterfowl habitats support a diversity of mammals, birds and fish, and commercial and subsistence resources for the villages of Wainwright, Barrow, and Nuiqsut and Kaktovik. The three most important areas for marine life are bays, lagoons and river estuaries. The bays support concentrations of marine mammals and fish in the summer. Within these shallower waters, walrus as well as bearded, ringed and harbor seals feed on bottom-dwelling invertebrates and fish. A variety of whales, including the grey, finback, humpback, sei, little piked, the Pacific killer, Beluga, and occasionally the endangered bowhead, congregate in the Wainwright, Barrow and Harrison Bays (see Figure 1-2 and 1-3 of Summer Biophysical Conditions). (Selkregg, 1975).

The lagoon systems, located on the inside or landward side of the barrier islands, are a "quite water" environment for wildlife. These lagoons -- which are found between Barrow and Dease Inlet, between the Colville River and Camden Bay, and near Kaktovik -- provide sheltered water in which marine mammals and fish migrate and feed during summer. Lagoons are also nesting and molting sites for waterfowl, resting areas for migratory geese, nurseries for young waterfowl, and feeding ground for many shorebirds.



Summer Biophysical Conditions: Wildlife

Musk Oxen Range

Caribou Calving Areas

Snow Geese & Waterfowl Habitats

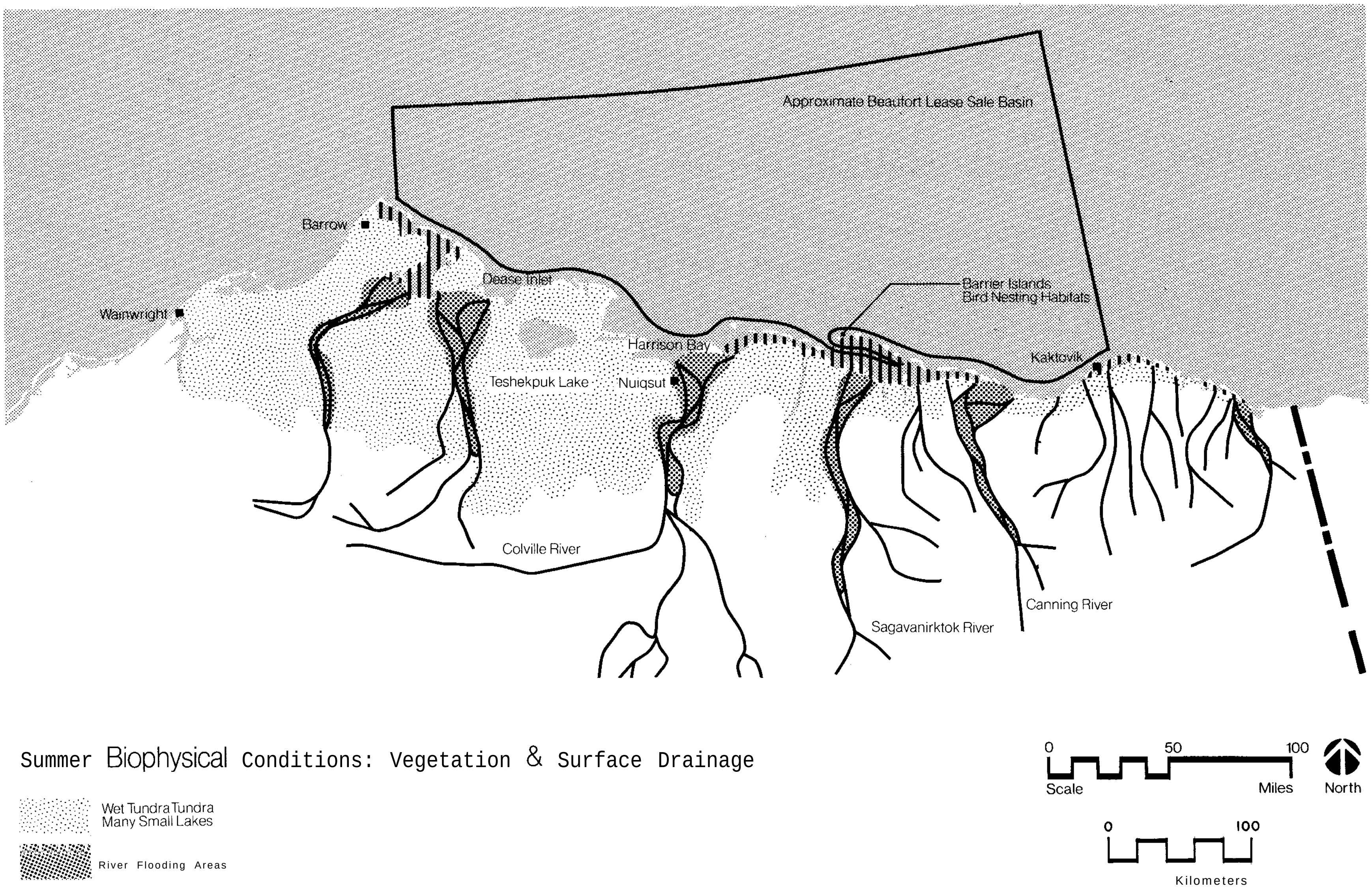
Figure I-2

Scale 0 50 100 Miles

North

0 100 Kilometers

Source: Selkregg, 1975



Summer Biophysical Conditions: Vegetation & Surface Drainage

Wet Tundra Tundra
Many Small Lakes

River Flooding Areas

Lagoon System Environmental Unit

Principal Rivers
and Streams

Figure t-3

Estuaries formed at river deltas, are low salinity environments which are habitat for waterfowl. The Sagavanirktok River Delta provides significant breeding habitat for snow geese (Selkregg, 1975).

Other aquatic habitats, including rivers, lakes and ponds are found on the coastal plain. The western portion of the coastal plain has fewer rivers, and is wider and less well-drained than the East Arctic. The flat topography of the plain is subject to widespread flooding by larger rivers in the spring. Both anadromous fish (tolerant to both fresh and salt water) and resident fresh water fish are found in these rivers.

1.5.1.2 Summer Terrestrial Wildlife Habitats

Mammals found in the onshore area include musk oxen, caribou, Arctic fox and wolves. Musk oxen range in the western portion of the Arctic National Wildlife Range, from Barter Island on the east to the Canning River delta on the west.

Caribou are divided between two major herds -- the Arctic herd found in the west, and the Porcupine herd found in the east. (See Figures 1-2 and 1-3). Additionally, there is a small resident herd of caribou found between Teshekpuk Lake and the Colville River (Alaska Department of Fish and Game, 1976a).

In March, the Arctic Herd leaves its wintering grounds in the Kobuk and Koyukuk River valleys and crosses the Brooks Range to its calving area in the upper Utukak and Ketik River drainages. Calving occurs from May to late June and migration generally continues onward toward the coast in a clockwise pattern to the general vicinity of Teshekpuk Lake and

Admiralty Bay. A southern migration commences in the fall. However, actual migration routes may vary from year to year.

The Porcupine Herd approaches its coastal calving ground in the Arctic National Wildlife Range south of Kaktovik in early March. They wander widely in the summer and return to their wintering habitat south of the Brooks Range in the Porcupine River valley in Canada (Resource Planning Associates, 1976).

Both caribou herds exhibit great variations in population size. The recent decreases in the size of the Arctic Herd (to 50,000 in 1976) may be caused by a variety of factors, including disease, climatic conditions, wolf predation, and hunting (Alaska Consultants, Inc., 1976).

L.5.1.3 Winter Marine Habitats

The Beaufort Sea has fewer fish and marine mammals in winter than in summer. Little is known of actual winter populations of fish beneath the polar ice pack. Grounded ice precludes overwintering of fish in most near-shore fast ice areas. Polar bear and Arctic foxes frequent the offshore ice during winter months as do seals.

1.5.1.4 Winter Terrestrial Habitats

Polar bears may den offshore on barrier islands and in shear ice pressure ridges, and as far as 32 to 48 km (20 to 30 miles) inland on lakeshores or river banks (Alaska Department of Fish and Game, 1976b). Denning sites of polar bears have been identified on the sandy northwest shore of Teshekpuk Lake, and the Colville and Canning River deltas. Females den in October and have their cubs in November or December, remaining in and near the den until early April (Alaska Department of Fish and Game, 1976b).

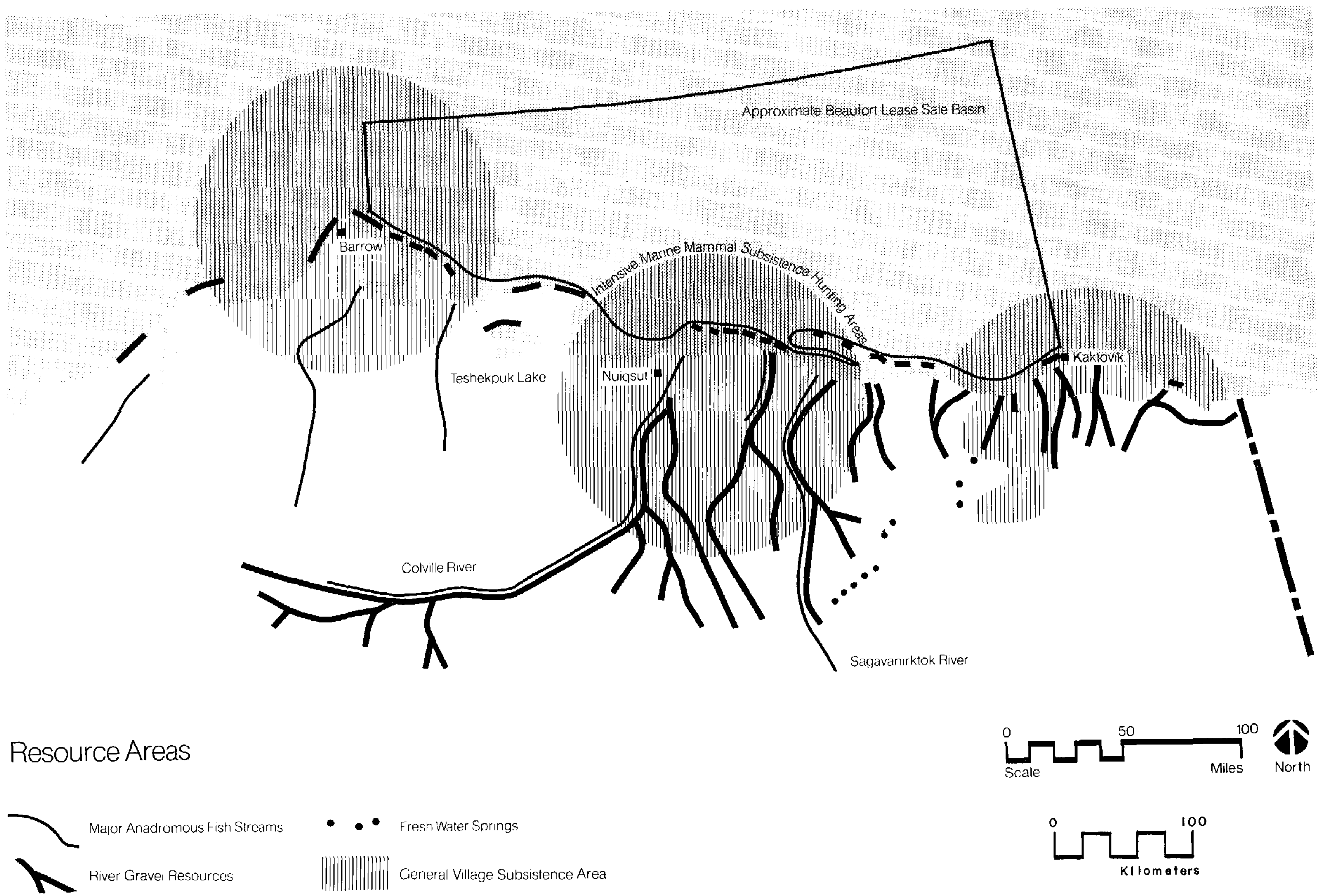
Small groups of caribou overwinter in the vicinity of Teshekpuk Lake, on Cape Simpson, and between Cape Halkett and the Colville River delta (Alaska Department of Fish and Game, 1976a). The number of caribou in these groups varies, but usually does not exceed fifteen animals. Wintering musk oxen utilize the same open, wind-swept coastal plains that are frequented during summer.

1.5.2 Resources

1.5.2.1 Gravel

Gravel and coarse sand are one of the Arctic's most valuable resources because these scarce aggregates are necessary for construction of roads, airports, work pads, fill and bedding for onshore pipelines and possibly offshore artificial islands. Aggregate may also be required for the manufacture of concrete.

North and west of Colville River, and within NPR-4, gravel and coarse sand deposits are limited; this is primarily because the Colville River intercepts much of the north-flowing drainage and coarse detritus originating in the western Brooks Range. Streams from the Utukok River east to the Colville contain predominately fine sand and silt, and gravel beaches are rare along the coast between the Colville River Delta and Point Barrow. Inland, the lakes of the coast plain are devoid of gravel deposits with the exception of the northwestern shore of Teshepuk Lake which has estimated reserves of 688,000 cubic meters (900,000 cubic yards) (Labelle, 1974). Gravel resources are shown in Figure 1-4.



Resource Areas

Figure 1-4

Within 40 km (25 miles) of Barrow, gravel and coarse sand resources are estimated to be 79 million cubic meters (25 million cubic yards) of which 2.3 to 3 million cubic meters (3 to 4 million cubic yards) are regarded as exploitable (Labelle, 1973). At Cooper Island about 40 km (25 miles) east of Barrow, 760,000 cubic meters (1 million cubic yards) are found. Between Cape Halkett and Drew Point 1-2 million cubic meters (1.6 mill ion cubic yards) of gravel and coarse sand exist along coastal beaches. Smith and Harrison Bays, however, are devoid of surface gravel although the possibility of subsurface gravel should not be precluded.

Extensive areas of fine to medium sand occur in stabilized and active dunes from the Colville River west to the Meade River and south to the foothills of the Brooks Range. The Colville River, as far north as the delta, is estimated to contain 27 million cubic meters (35 million cubic yards) of gravel, but the delta is composed of silt and fine sand (Labelle, 1974) .

The above estimates of gravel and sand resources should be treated with caution since they are based upon aerial or surface observations and not depth/volume measurements obtained from borehole data.

Less is known about the gravel resources east of the Colville River. Most of the major streams that head in the Brooks Range contain sand and gravel . Coastal resources east of the Colville are available in beaches, spits and barrier islands. Significant gravel deposits occur in a series of coalesced alluvial fans along the flanks of the Brooks Range east of the Canning River.

Few data are available on offshore seafloor or subsurface gravel and sand deposits which are particularly important with respect to the possible demand for offshore aggregate for artificial island construction. On a regional scale, from the shoreline to the 20 m (60-foot) isobath, east of the Colville River delta the bottom sediments consist mainly of sands and gravels whereas west of the delta sediments are silts and clays (National Oceanographic and Atmospheric Administration, 1977) .

River gravel resources in the Arctic are further limited by problems associated with extraction. The Alaska Departments of Fish and Game and Environmental Conservation prohibit gravel removal from the Colville River delta and from other rivers, such as the Sagavanirktok and Kuparuk, without prior approval of a plan showing pit location and specific quantities of gravel required. Data on the total amounts of gravel which have been extracted to date from the Sagavanirktok River for construction of the Prudhoe Bay facilities and Alyeska Pipeline are not available, but estimates for Prudhoe Bay indicate more than 76 million cubic meters (100 million cubic yards) had been used by 1974 (Arctic Institute of North America, 1974). Gravel has not been extracted from the Arctic National Wildlife Range since its establishment in 1960.

Natural beach erosion occurs as a result of storms and along river banks as a result of flooding. Gravel removal from beaches could disrupt fish and marine mammal habitats and speed coastal erosion. The removal of gravel from the barrier islands is discouraged and removal from the Colville River delta is closely monitored; elsewhere gravel removal is permitted only after state approval of a plan which demonstrates that no damage will occur to marine habitats or that coastal erosion will not be accelerated (Alaska Department of Fish and Game, 1976c). Nonetheless, some coastal beaches have been used as gravel borrow sources adjacent to NPR-4.

1.5.2.2 Water

Water will be required for base camps, hydrostatic testing, reinfection into wells, for mixing drilling mud and for construction of ice roads in winter. Water is abundant on the North Slope during the summer and fall months. However, during the eight month Arctic winter, nearly all rivers, streams and lakes freeze to the bottom. A few pockets of unfrozen water can become the crowded habitats of overwintering fish. During this period, water availability is limited because most water is in the form of either ice or snow. Some ground water may be present in alluvial aquifers near large rivers and beneath larger lakes which do not freeze to the bottom. Deep lakes and melted snow and ice are the primary existing sources of community water in winter.

In summer, permafrost creates a barrier to subsurface drainage, causing a near-surface water table which again freezes in winter. Developing ground water sources below the permafrost is not practical because the permafrost extends from several feet below the surface to depths between 180 m (600 feet) and 600 m (2,000 feet). In addition, the water is often brackish and generally not suitable for industrial and domestic use.

Besides natural limitations on water availability, especially during the winter, state regulations on extraction and use also limit the availability of water resources. The Alaska Department of Fish and Game regulates the removal of fresh water from certain rivers such as the Colville, Kuparuk and Sagavanirktok (Grundy, 1977).

1.5.2.3 Subsistence Areas

The coastal peoples of the Arctic rely on caribou, small game such as ptarmigan and owls, bird eggs, whales, seal and fish as part of their subsistence food resource. Spawning areas, overwintering fish sites, calving grounds, and nesting sites are, therefore, important subsistence locations for Eskimo people.

Nearshore coastal migration routes, within a day's access of native villages, are fished and hunted most intensively (see Figure 1-4, Resource Areas), although land and water hunting and fishing areas exist for longer and more distant trips by aircraft or snow machine. In the nearshore areas, ice-breeding harbor seals, ringed seals, and bowhead, beluga and grey whales are taken. Harrison Bay is an important beluga whale subsistence hunting area. Although whales provide large amounts of meat and fat, seals are the staple of the Eskimo diet (Selkregg, 1975). A small commercial fishery has operated in the Colville River delta since 1950 harvesting cisco and white fish. The largest subsistence fisheries in the Arctic are conducted at Point Barrow, Kaktovik and Point Hope, mainly taking white fish and cisco (Selkregg, 1975). In addition, residents at Point Hope and Kaktovik harvest char for personal use.

Caribou have always been an important food source in the Arctic. Today, caribou are still taken in large numbers, but the Alaska Department of Fish and Game has instituted a permit system which establishes seasonal limits. Most caribou hunting is done when the ground is frozen and snow machines can be used for transportation. Most of the migrating caribou herds leave the Arctic by early fall, but some remain longer and can be hunted in the winter.

Other animals are sought primarily for their pelts to make clothing for residents and to sell on the open fur market. Wolves, polar bear, Arctic fox and other fur-bearing animals are sought for the commercially-marketable furs. Marine mammals with the exception of polar bear and walrus, may be used for subsistence or commercial handicrafts by Natives only under the Marine Mammal Protection Act of 1972.

1.5.3 Land Use Planning and Regulations

The development of OCS staging areas and utility corridors crossing federal and state lands will require compliance with regulations and response to planning concerns of federal, state and borough agencies and their jurisdictions. These regulations and concerns can be grouped under those which have application anywhere on the North Slope, and those which apply only to bounded jurisdictions, such as the National Petroleum Reserve - Alaska.

North Slope Regulations: Agency planning and regulatory concerns which will influence development throughout the North Slope include:

- Planning activities of the Joint Federal-State Land Use Planning Commission (JSFLUPC);

- Planning considerations of the Coastal Management Program and the North Slope Borough; and

- Environmental stipulations relating to nearshore areas and waterways established by Alaska Department of Fish and Game, the Alaska Department of Environmental Conservation; federal legislation; and the U.S. Army Corps of Engineers.

Specific Jurisdictions: Planning activities and specific regulations for bounded jurisdictions include those established for:

- Federal pipeline rights-of-way for NPR-A and the Arctic National Wildlife Range;

- Pipeline rights-of-way across state lands between the Colville and Canning Rivers;

- Naval Petroleum Reserve No. 4 exploratory and planning activities; and

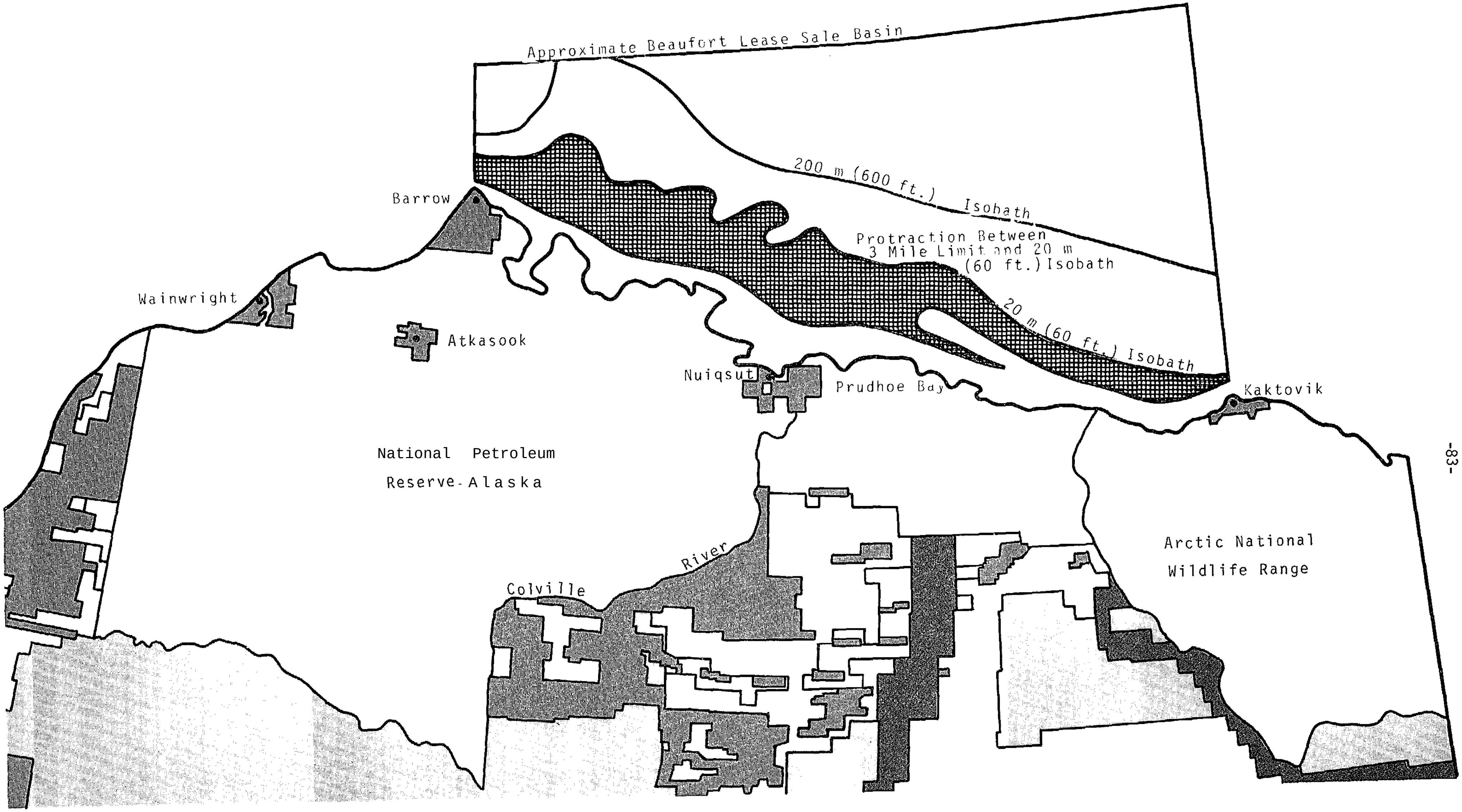
- Arctic National Wildlife Range environmental stipulations.

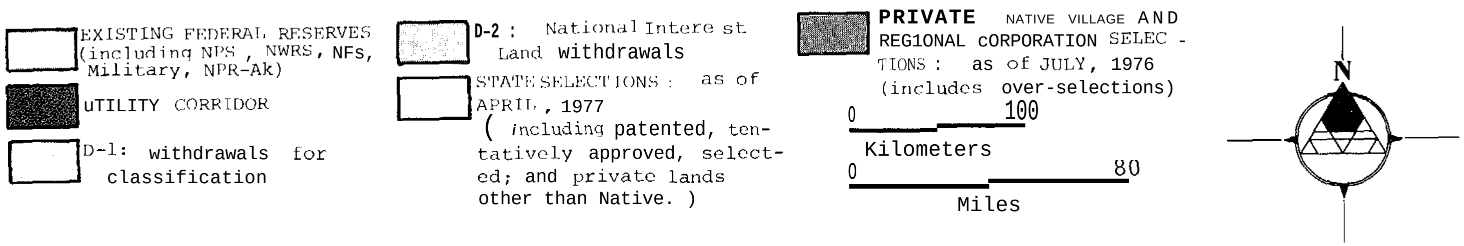
The boundaries of these jurisdictions and the land selections of native villages are shown in Figure 1-5, Land Status.

1.5.3.1 Agency Planning and Regulatory Concerns

- Joint Federal-State Land Use Planning Commission

  The Joint-Federal State Land Use Planning Commission (JFSLUPC) was created byanAct of Congress in the





LAND STATUS
Figure 1-5

Alaska Native Claims Settlement Act of 1971. The Commission makes recommendations on land use and land status, and coordinates intergovernmental planning activities. Planning concerns of the Commission may be reflected in the regulatory activities of other federal, state and borough agencies. Some of these concerns have broad application to petroleum development activities, including the locations of ports and pipelines.

The Commission recently expressed the opinion that "the surface transportation network that develops in northern Alaska will depend upon the pace of oil and gas development primarily, and upon the future of mineral ore production secondarily" (Anchorage Daily News, January 21, 1976). This position responds to issues raised by State plans for conversion of the Alyeska Pipeline haul road into a public highway. Public use of the road not only could have an impact on adjacent resource lands, but also could encourage the growth of nearby communities.

The construction of onshore pipelines to serve OCS development also will require construction of a parallel haul road. In response to land use planning issues surrounding discussion of the Alyeska pipeline haul road, the JFSLUPC now encourages pipeline routing studies to take place in the context of regional transportation planning.

Other studies by the Commission are of relevance to pipeline corridor routing. In October 1974, the Bureau of Land Management released a conceptual study of Multimodal Transportation and Utility Corridor Systems in Alaska (U.S. Department of the Interior, 1974b). The JFSLUPC found that the BLM study was essentially only a physiographic analysis of alternative corridors. The Commission recommended that facilities be constructed in a manner which would not have a significant impact on the primary uses for which the lands have been designated. It also recommended that no fixed corridors be established until found to be in conformance with a statewide transportation plan. An essential ingredient of this plan would be participation in transportation decisions by residents of areas affected by such facilities.

An Alaska State/Federal Transportation Planning Organization has been established to consider transportation issues, policies and programs required by resource development and land selection and land use, leading to the development of state transportation plans. The first meeting of the organization was held February 4, 1977.

0 Coastal Management Program

In 1974, Alaska initiated a Coastal Management Program through the U.S. Coastal Zone Management Act of 1972. The purpose of the program is to improve coordination among governmental, land and water management agencies, to promote more effective resource management, and to involve citizens in such decision making.

In 1977, the Alaska State Legislature passed the Alaska Coastal Management Act which establishes a process by which development of a State Management Program, in progress since 1974, may be facilitated (Alaska Division of Policy Development and Planning, 1977). The program will be guided by a newly created Alaska Coastal Policy Council, consisting of nine public members from each of nine general State regions outlined in the Act and seven designated members from each of seven State government agencies. A major part of the program is the establishment of local or district coastal management programs which will be overseen by the council who will set the program guidelines. District programs will be developed by (a) all municipalities with planning power, or (b) by remaining areas in the unorganized borough which may elect to organize into “coastal resource service areas”. The district programs are required to reflect each resident’s concerns.

The district program management elements include:

1) Delineation of coastal area boundaries;
2) Statement of land and water uses and activities subject to the program;
3) Policies to be applied to those uses;
4) Regulations to be applied to those uses;
5) Description of proper and improper uses and activities in the coastal area;
6) Policies and procedures which will determine whether specific proposals will be allowed in the coastal area; and
7) Designation of and policies concerning "areas which merit special attention", as defined in the Act.

District programs will be implemented through existing land use controls in municipalities. State agencies are required to review and modify their own authorities and procedures to facilitate full compliance with district programs. The active input of local government and residents to the State's programs should result in the tailoring of land use and resource use regulations and policies to local conditions and needs.. A significant effect can be anticipated on the siting and location of petroleum facilities, and other offshore petroleum developments.

The North Slope Borough has instituted its own Arctic Coastal Zone Management Program (CZM), and is actively involved in making known its interests in the overall Program (Alaska Consultants, Inc., 1974). Because of issues already raised by the CZM Program, a proposal now exists for the North Slope Borough to define a borough and State legal position which would protect the rights of Inupiat Natives to subsistence areas beyond the three-mile territorial limit.

Specific functions of the Coastal Management Program will include the monitoring of OCS development activities. Federal amendments to the Act of 1976 specifically respond to land management issues raised by the accelerated OCS program. The amendments caution that there is a real possibility of delay or disruption in federal plans for needed new and expanded OCS oil and gas production unless coastal states are assured of the means of coping with or ameliorating the impacts from such activities.

Once the State Coastal Plan had been approved by the federal government, OCS activities in the coastal zone must be consistent with the plan. Facilities or pipeline landfalls may then only occur in areas identified for such use by the approved state management program. It has yet to be determined whether or not the OCS lease sale areas are also covered under the requirements of an approved State program.

0 Environmental Stipulations for Nearshore Areas and Waterways

This section discusses environmental stipulations related to water, gravel and wildlife resources. (Additional stipulations relate to such petroleum development activities as air quality control of hydrocarbon emissions, disposal of drilling formation waters and solid waste; but only those which address particular locational concerns are included here.)

Responsibilities for protection of fish and wildlife resources along with the Beaufort Sea coast and its navigable waters and streams are vested in the Department of Interior and the U.S. Army Corps of Engineers.

The Estuarine Area Study Act of 1968 and earlier statutes provide the Secretary of Interior with rights of protection of fish and wildlife resources from any activity or structure encroaching into coastal waters (U.S. Department of the Interior, 1974a). This broad mandate could control the size and length of gravel causeways carrying offshore pipelines, the dredging of barge channels and the modification of rivers, bays and lagoons would come under particular review (the sensitivity of these coastal waters to disruption is discussed under Section 1.4.1.1, Summer Biophysical Conditions).

The Army Corps of Engineers had additional requirements for compliance with existing codes and regulations to keep adverse effects to a minimum before issuance of permits for the development of permanent offshore drilling platforms, terminals and docking facilities in navigable waters (U.S. Army Corps of Engineers, 1975).

1.5.3.2 Jurisdictional Regulations

In addition to the land use planning and regulatory concerns described above, petroleum development activities will also be regulated by specific requirements of (1) the National Petroleum Reserve - Alaska; (2) State lands west and east of Prudhoe; and (3) the Arctic National Wildlife Range.

o Pipeline Rights Through NPR-A and the Arctic National Wildlife Range

  Pipeline rights-of-way through federal lands must be approved by the Secretary of the Interior under the Mineral Leasing Act of 1920, as amended. Part of the application for pipeline rights-of-way requires a plan which addresses environmental and cultural issues, including requirements ales"igned to control damage to fish and wildlife habitats, and to protect subsistence resources (U.S. Department of the Interior, 1976).

An Act with similar intent exists for natural gas pipelines. The Natural Gas Act empowers the Federal Power Commission to issue a "certificate of public convenience and necessity" for gas pipelines across federal lands.

o <u>Pipeline Rights-of-Way Across State Lands</u>

Pipeline rights-of-way across state lands require approvals of the Department of Natural Resources and the Division of Lands. The Director of the Division of Lands may give preference to uses which will be of the greatest economic benefit to the state and to the development of its resources. For "distribution pipelines" and secondary roads, this action may proceed without prior approval of the Commissioner of Natural Resources.

The Alaska Right-of-Way Leasing Act, however, empowers the Commissioner of Natural Resources to review non-competitive right-of-way on state lands. Requirements include the Commissioner's assessment of whether or not a pipeline would conflict with existing land uses, including subsistence. As with the Federal Mineral Leasing Act, the State Leasing Act requires consideration of potential adverse environmental impacts, and plans for restoration and revegetation of leased lands.

0 Naval Petroleum Reserve No. 4 (NPR-4)

Recent exploration activities initiated by the Navy and continued by the Department of the Interior have aroused controversy. These activites include the drilling of exploratory wells including one on the shore of Teshekpuk Lake, and seismic exploration.

Residents of Barrow and other villages have expressed concern about this exploration program particularly with respect to subsistence food resources such as fish and caribou (Resource Planning Associates, 1976).

On June 1, 1977, Naval Petroleum Reserve No. 4 became National Petroleum Reserve - Alaska with transfer of control from the Navy to the Department of the Interior. As part of this transfer, the Congressional Act required that a land use plan for NPR-4 be prepared by the Department of Interior and coordinated by Bureau of Land Management with assistance from the National Park Service, Bureau of Mines, U.S. Geological Survey, Bureau of Indian Affairs and U.S. Fish and Wildlife Service. The Task Force is also composed of representatives of the North Slope Borough, the Arctic Slope Regional Corporation and the Office of the Governor. The study will evaluate such factors as Native values, scenic, historic, recreational, fish and wildlife and wilderness values, and mineral potential. It is scheduled for completion by April 1979.

In 1972, the Navy unilaterally redefined the boundaries of NPR-4 to include coastal tideland areas of Smith Bay, Harrison Bay, Peard Bay and Kasegaluk Lagoon (Skladel , 1974) . The executive Order establishing the Reserve in 1923 defined its northern Arctic Ocean boundary as the highest highwater mark of the coast of the mainland. The Navy redefined this boundary as the mean highwater mark, thereby assimilating potentially oil-rich submerged lands from the State of Alaska. To date, the State has made no formal response to the Navy's action. The significance of the issue of Navy versus State ownership could conceivably affect pipeline alignments from wellhead to landfall within these tideland areas.

0 <u>Arctic National Wildlife Range</u>

The Arctic National Wildlife Range extends from the Canning River at Camden Bay to the Canadian border, and south across the Brooks Range, approximately 150 miles from the Beaufort Sea. Included within its boundaries is the calving area of the Porcupine caribou herd. a musk oxen range, the principal fall staging area for snow geese migrating eastward into Canada, and significant populations of Dan sheep and grizzly bear.

As part of the "National Interest" Federal Parkland Selections under the provisions of Section d-2 of the Alaska Native Claims Settlement Act, the Department of Interior in October 1974 proposed an expansion of the Range to include an additional 3.7 million acres south and west of the existing Range, the establishment of additional restrictions for protection of Range values, and the incorporation of the Range into the National Wilderness Preservation System (U.S. Department of the Interior, 1974a).

Although this proposal has yet to be finally acted upon, its concerns will be reflected in any Interior decision regarding offshore or onshore OCS petroleum development activities centered in Camden Bay.

The Secretary may grant rights-of-way across National Wildlife Refuge lands for a variety of purposes, including pipelines and supply roads. However, such activities must be compatible with the purposes for which these areas are established. Restrictions will probably focus on the sensitive winter habitats of polar bear, waterfowl nesting and molting areas, and habitats of moose, wolves and barren-ground grizzly bear.

Other objectives of the National Wilderness Preservation System include protection of wild and scenic rivers, archaeologic and historic values, fish resources and recreational use of fish and wildlife consistent with preservation of biotic communities.

CHAPTER II

PETROLEUM DEVELOPMENT SCENARIOS

2.1 SCENARIO DEFINITION

Petroleum development scenarios are a useful tool to assist planners and policy makers in assessing the likely events and interrelationships of any series of petroleum related decisions. Each scenario should explicate the stream of likely, interrelated events and decisions which flow from a particular development decision, as well as identify key variables and alternative outcomes. The petroleum development scenarios are made up of a number of components each of which is linked to the others and each of which establishes the parameters which affect all subsequent components. Among the scenario components are:

- Field size and location
- Level of oil and gas production
- Tracts (sold, explored, and held)
- Numbers and types of offshore platforms and wells
- Equipment and material requirements
- Logistics
- Manpower and construction activities
- Pipeline and transportation requirements and specifications

- Onshore facilities and structures

- Time schedules for exploration, development, production, and shut down.

The petroleum development scenarios in this report draw upon United States Geological Survey (USGS) estimates of the level of petroleum resources in the Beaufort Sea: a low level of resources (a conservative estimate with a 95 percent probability of occurrence), a most likely level (mode of distribution), a high level (an optimistic level of resource discovery with only a 5 percent probability of occurrence) and a “bonanza” level (a highly optimistic level of resources with only a 2 percent probability of occurrence as extrapolated from USGS data).

Typically, where impact projections are required, the high-level estimate is preferentially used in an attempt to focus upon the maximum impacts to the physical and social environment (the bonanza level is unique to this particular analysis). Moreover, in many scenarios, the high-level resource estimate is also depicted as being artificially concentrated in a specific geographical location, in order to enhance the perception of impacts. Thus, a typical scenario may lead to projections much more pronounced than would be indicated by average or “most likely” expectations.

In contrast, the scenarios generated in this report are designed to explore the full range of potential oil development activities, and to reflect the practical economic constraints and physical characteristics of petroleum activities appropriate to the area.

Impact variation and petroleum characteristics are introduced into the scenario construction process through the following:

- All three published USGS resource level estimates--high, mode (as inferred from the USGS definition of "statistical mean" (Circle 725, p. 21) low--were considered. In addition, a "bonanza case", reflecting an extrapolation of the USGS distribution curve to the 2 percent probability level, was evaluated. The latter was arbitrarily selected for the purposes of providing still greater variation to the analysis, and to explore the potential impacts of a relatively large find in the Beaufort OCS area.

- An attempt was made to reflect the geological reality of hydrocarbon deposits by distributing them geographically according to a log-normal distribution pattern. The total resources were distributed into three major "concentrations," or clusters of fields (60%, 30% and 10% of total resources, respectively) that could be separated geographically into developable "building blocks". Further, each of these resource levels was again dispersed into large, medium and small fields. From this distribution, it was possible to select a range of building blocks, with which the economics and impacts of potential petroleum development situations could be explored.

- Geographical variation was also introduced by arbitrarily selecting three locations of possible offshore discovery--

Western Beaufort Sea near Barrow, Central Beaufort Sea near Prudhoe Bay, and Eastern Beaufort Sea near Camden Bay and Barter Island (Kaktovik). These hypothesized discovery sites effectively reduce the probability of any given resource level being found at the specific location to one-third of the USGS probability. Thus, the resources have been defined in terms of both dispersion patterns and geographical locations. It is to this multi-layered and more flexible design that the decisive factors affecting scenario selection-variation in economic, technological, environmental and socioeconomic factors--can be applied to formulate a final set of scenarios. With this structure, more meaningful development possibilities for impact analysis can and do emerge.

The remainder of this report goes through the specific methodology for scenario construction; the technological conditions, assumptions, and economic factors which are crucial in determining the feasibility of the scenarios; assumptions pertaining to scenario manpower and locational siting; and the process of selection leading to the final scenarios which are described in detail.

2.2 SCENARIO CONSTRUCTION

This section proceeds from the most recent USGS estimates of recoverable resource deposits of oil and natural gas in the Beaufort Sea to the generation of 15 petroleum development scenarios. Each scenario represents one of five unique levels of resource concentration to be found in any of three arbitrarily assumed locations. This set of scenarios could be expanded indefinitely by permuting each of the large number of technical factors that must be considered (or fixed by assumption) in any hypothetical framework. For reasons of expediency and manageability, the number of "outcomes" is limited to 15, and is the result of permuting only two variables: resource size and location of discovery. These two variables correspond to the scale dimension and the spatial dimension that are critical to onshore (community) impact analysis.

The 15 scenarios here developed should be regarded as "skeletal", acquiring form as the technical, operational and economic assumptions are developed throughout the next two chapters of the report. Ultimately, the scenarios can be evaluated on the basis of investment requirements and compared to a range of investment objectives to determine their economic feasibility.

2.2.1 USGS Estimates of Petroleum Resources in the Beaufort Sea Lease-Sale Area

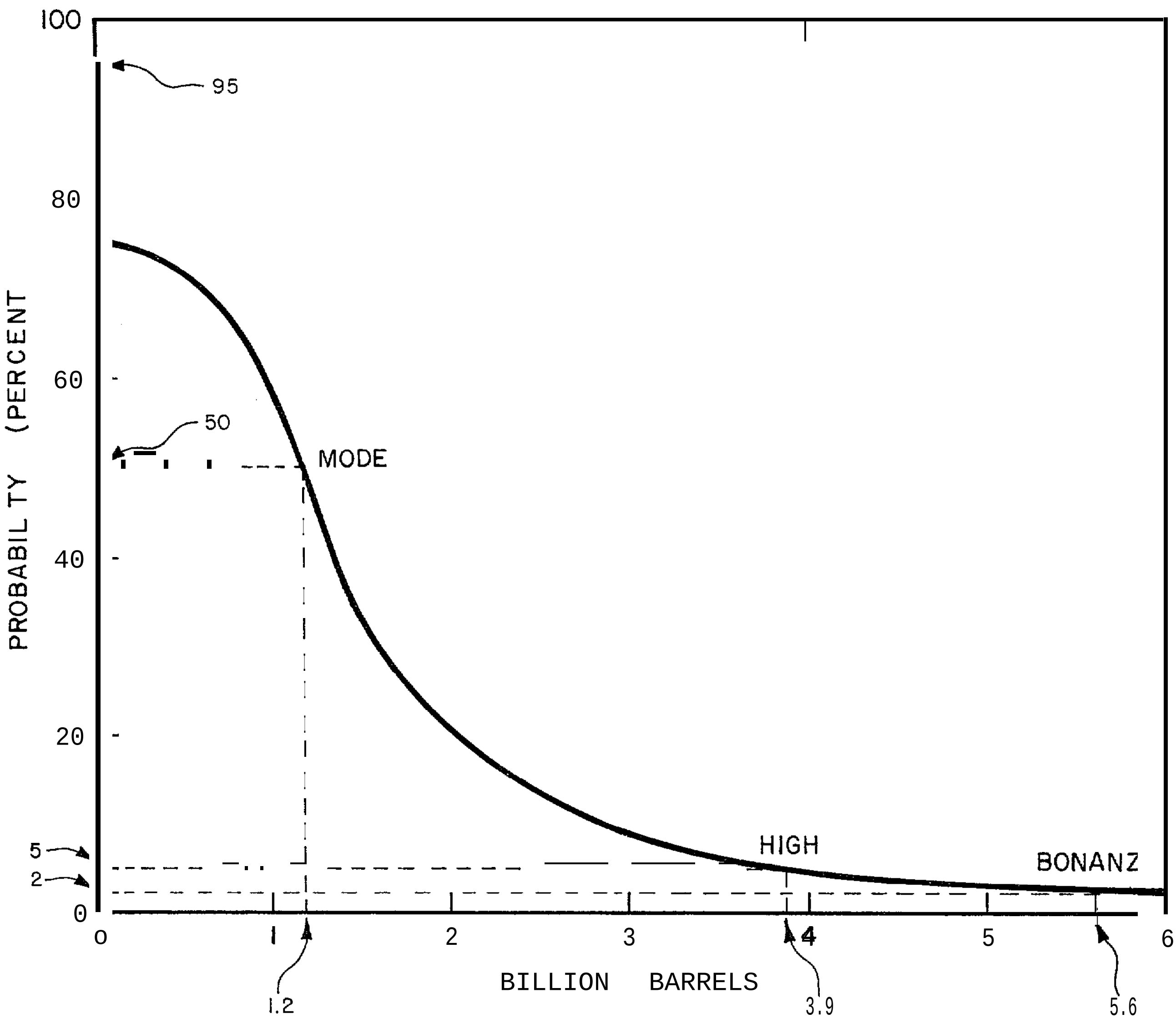
USGS arrives at estimates of recoverable resources through a delphi process of their own judgments in which a log-normal probability of resource discovery is ascribed to the individual geologic provinces. These informed opinions are then summed into a probability distribution. Their estimates thus appear as "low" (95 percent chance of occurrence), "high" (5 percent chance of occurrence), and "average" (high, low and mode divided by three). In a recent working paper (Open-File Report 76-830, Grantz et al., July, 1976), the USGS compiled an estimate of the recoverable resources in the Beaufort Sea area between 156 and 144 degrees longitude, and seaward to the 200-meter isobath:

USGS Estimates to 200-Meters

	Oil (Billions of Barrels)	Gas (Trillions of Cubic Feet)
High	7.6	19.3
Mean	3.3	8.2
Low	0	0

The low estimate is shown as “zero” because the USGS thinks there is a good possibility of finding uneconomically recoverable resources in the Beaufort Sea, and has truncated 25 percent of the probability distribution (from 100 percent to 75 percent) to reflect this possibility (see Fig 2-l).

The USGS figures presented above were used as the basis for the resource discovery probability curves (Figure 2-l). First, the “most likely” level, or mode, of the distribution (2.3 billion barrels, 5.7 tcf) was determined from the definition of the estimate values. The mode of a log-normal distribution generally corresponds to a 70 to 60 percent chance of occurrence. However, because of the truncation of the distribution, the modal value was ascribed to the 50 percent chance of occurrence. Secondly, all the figures were reduced in direct proportion to the area of the continental shelf lying between the three-mile limit and the 20-meter (60-foot) isobath. This 20-meter (60-foot) isobath generally



U.S.G.S. ESTIMATE OF OIL
RESOURCE DISCOVERY PROBABILITY

U.S. BEAUFORT SEA 3 MILE LIMIT TO 20 M (60 FT) ISOBATH corresponds to the shear zone (stamukhi zone) between the land fast ice and the polar ice pack (see Figure l-la and l-lb). Because of concerns about the exposure of petroleum drilling structures to sea pack-ice and the potential for bottom-gouging by ice, this 20-meter (60-foot) depth was assumed to be at least a temporary technological barrier to petroleum development. From published sources (USGS Open-File Report 76-830, Grantz et al, 1976, page 16), it was determined that about 60 percent of , the shelf area under consideration lies between O and 20 meters (O and 60 feet), and 40 percent between 20 and 200 meters (60 and 660 feet). Of the former, about 85 percent is federal land and 15 percent state land. Using these two factors (85 percent x 60 percent = 51 percent), the USGS estimates were accordingly reduced. Lastly, to expand the variation in analysis, it was decided to extend the upward limit of hypothetical discovery by considering a “bonanza” case reflective of the 2 percent probability level on the USGS distribution. This was obtained through graphical extrapolation of the USGS distribution curve (see Fig. 2-l). Given these modifications, the USGS estimates are as shown in Table 2-1.

2.2.2 Field Size Distribution

The resource estimates shown in Table 2-1 represent various levels of hypothetical resources to be found somewhere in an area in excess of 12,950 square kilometers (5,000 square miles). They say nothing of the probable location, nor even of the extent of geographical concentration. Since it is improbable that the petroleum resources will be spread

Table 2-1

Estimates of Recoverable Oil and Gas Resources
in the Beaufort Sea Between the
Three-Mile Limit and the 20 m (60-Foot) Isobath

	Oil (10^9 bbls)	Gas (10^{12} Cf)
Bonanza[1]	5.6	14.1
High[2]	3.9	9.9
Most Likely[3]	1.2	2.7
Low[4]	0	0

(1) Determined graphically from a plot fitted to three points given by USGS

“(2) Given by USGS

(3) Calculated from USGS formula

mean reserve = 1/3 (modal reserve + high reserve + low reserve)

(4) Assigned from a 25 percent truncation of the probability distribution

Note: All estimates are derived from U.S. Geological Survey estimates contained in Circle 725 (Miller et. al., 1975) and Open-File Report 76-830 (Grantz et al., 1976).

uniformly throughout the entire OCS area or concentrated into a single giant field, distribution factors must be applied.

The concentration of oil fields worldwide generally follows a log-normal distribution. For the purposes of the study, the deposits were arbitrarily distributed into three geographic concentrations of 60 percent, 30 percent, and 10 percent of the total reserves. As such, each concentration, or cluster of fields, is presumed to have an equal chance of being discovered in any of the three general locations (east, central, or west) which are delineated in the next section of the report.

Similarly, the distribution of individual petroleum fields <u>within</u> each of the above concentrations (clusters of fields) is presumed to follow a log-normal distribution. The particular distribution pattern employed in the study is as follows:

32 percent in large fields (1 billion barrels or more)

43 percent in medium-size fields (500 million to 1 billion barrels)

25 percent in small fields (100 million to 500 million barrels)

Applying these two sets of distribution factors consecutively to each of the USGS estimates yields the profile that is shown in Table 2-2. For example, a 60 percent concentration of the bonanza resource level estimate of 5.6 billion barrels equals 3.5 billion barrels. Of this, 43 percent is said to be found in medium-size fields (3.5 billion barrels x .43 = 1.5 billion barrels; which can roughly be interpreted as two 750-million barrel fields).

TABLE 2-2

Resource Estimates by Geographic

Concentration and Field-Size Distribution

Resource Estimate	Geographic Concentration	Number of Fields Within each Concentration by Field Size		
		Large	Medium	Small
Bonanza Estimate	3.5	1	2	4
(5.6 billion bbl.)	1.5	1	0	2
	0.6	0	1	0
	5.6 billion bbl	2	3	6
High Estimate	2.3	1	1	2
(3.9 billion bbl)	1.2	0	1	1
	0.4	0	0	1
	3.9 billion bbl	1	2	4
Most Likely	0.7	0	1	0
Estimate	0.4	0	0	1
(1.2 billion bbl)	0.1	0	0	1
	1.2 billion bbl	0	1	2

2.2.3 Scenario Building Blocks

The nine geographic concentrations, as shown in the second column in Table '2-2 may be inferred to represent only six unique discovery possibilities or "building blocks". For example, the 1.5 billion barrel concentration of the bonanza resource estimate is analogous to the 1.2 billion barrel concentration of the high resource estimate, and therefore an intermediate value of 1.4 billion barrels is assumed. Similarly, the 0.6 and 0.7 billion barrel concentrations can be considered nearly the same for the purposes of the study. Thus, the six building blocks are as follows:

Scenario Building Blocks

Oil	Gas
3.5 billion barrels	8.8 trillion cubic feet
2.3 billion barrels	5.8 trillion cubic feet
1.4 billion barrels	3.5 trillion cubic feet
0.7 billion barrels	1.8 trillion cubic feet
0.4 billion barrels	1.0 trillion cubic feet
0.1 billion barrels	0.25 trillion cubic feet

The smallest building block (0.1 billion barrels, 0.25 tcf) was determined not to be developable in the Beaufort Sea OCS context for economic reasons, and was dropped from further consideration.

In each case, it may be seen that natural gas resources are presumed to be found in the ratio of 2,500 cubic feet of gas per barrel of oil (USGS Open-File Report 76-830, Grantz et al., 1976). These building blocks represent an assumed level of ultimate recovery of oil and natural gas to be arbitrarily located in any one of the three geographical areas postulated in the study.

2.2.4 Geographic Locations

Three geographical locations corresponding to “east”, “west”, and “central” were arbitrarily selected as the hypothetical discovery sites for the building block reserve estimates. These sites should not be construed to reflect any preexisting knowledge of hydrocarbon deposits, but rather were chosen for illustrative purposes in order to extend the geographical flexibility of the analysis. The eventual purpose of the scenarios is to provide a broad-based assessment of the socioeconomic impacts of OCS marine mineral development in the Alaskan Beaufort Sea, and this can best be done by exploring a range of developmental possibilities with respect to both magnitude and location of development.

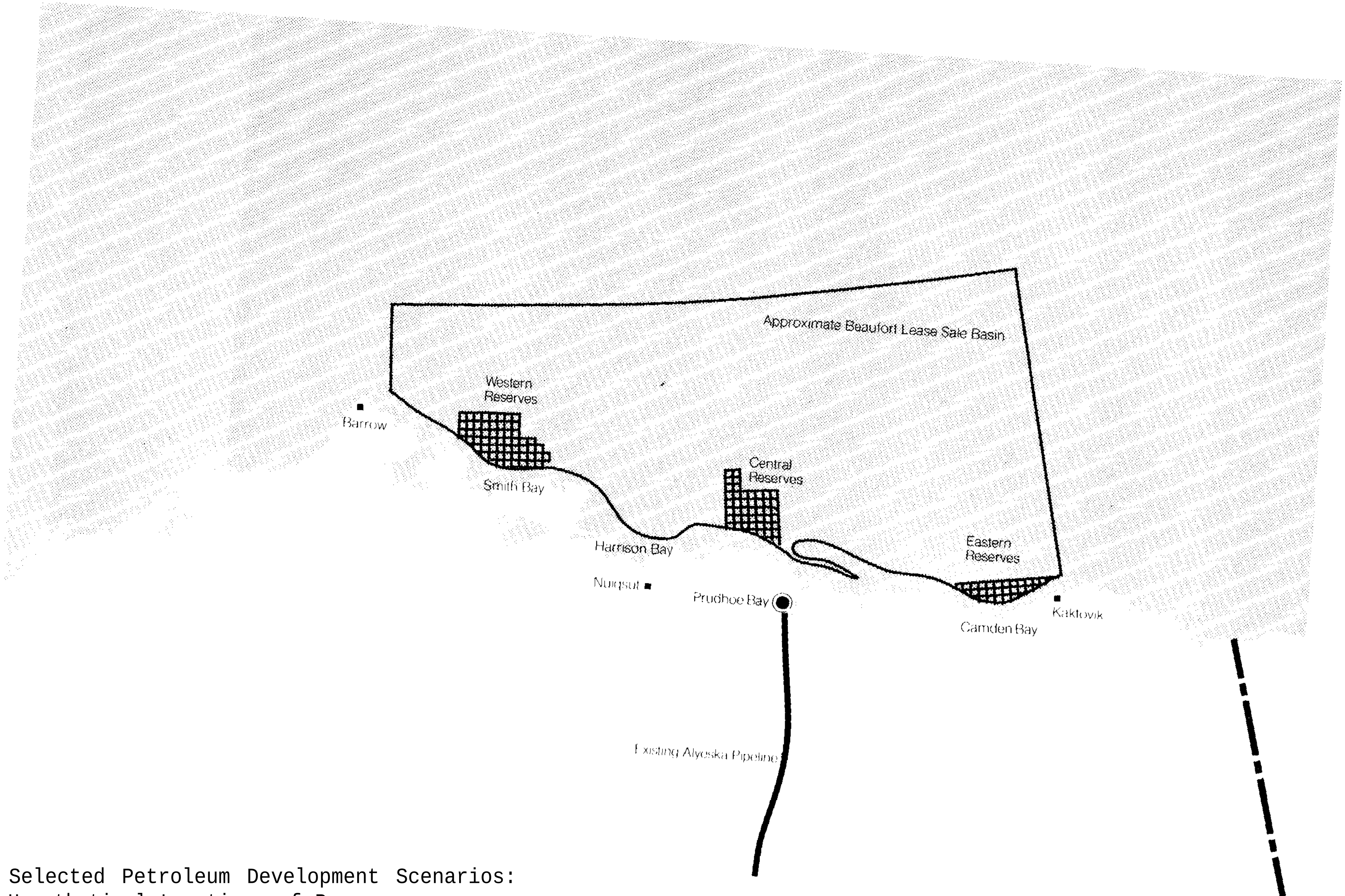
The analysis required a higher level of geographic specificity than simply east, west and central “basins”. The locations of hypothetical discovery used in the analysis have therefore been arbitrarily positioned with respect to Bureau of Land Management protraction diagrams of the Beaufort Sea waters, along with the appropriate “tract” numbers. These protraction diagrams represent a platting of the offshore waters into tracts of nominal 2,304 hectares (5,693 acres), 4,800 m by 4,800 m (3 miles by 3 miles). A universal coordinate system is used in the platting, and because of the curvature of the earth and the irregularities of the state and federal boundaries, not all tracts have a full complement of 2,304 hectares (5,693 acres). In fact, some of the numbered tracts are merely odd-shaped pieces of otherwise square tracts. The Beaufort Sea area between 156 and 144 degrees longitude, the 3-mile limit, and the 20-meter (60-foot) isobath are estimated to contain over 600 tracts. Another 40 tracts may become available when the offshore demarcation between the U.S. and Canada is clarified at 141 degrees. The tract locations selected for the scenarios, which are shown in Figure 2-2, are detailed below:

o Central and North of Jones Island (40 tracts, about 84,177 hectares (208 ,000 acres)

Beechy Point Quadrangle: Tracts 68-69, 112-113, 156-157, 200-205, 244-249, 288-293, 332-337, 376-381, 423-425, and 469.

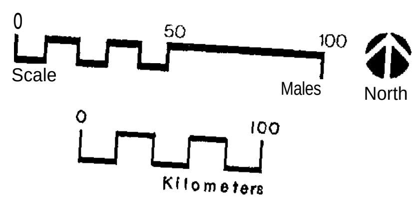
o Eastern (33 tracts, about 56,253 hectares or 139,000 acres)

Camden Bay, Flaxman Island Quadrangle: Tracts 847-860, 893-902, 940-944, 984-987.



Selected Petroleum Development Scenarios:
Hypothetical Locations of Reserves

Figure 2-2



0 Western (72 tracts, about 147,715 hectares or 365,000 acres)

Off Teshekpuk Lake and Smith Bay, Dease Inlet Quadrangle: Tracts 734-741, 778-785, 822-829, 867-875, 912-920, 957-965, 1002-1010; Teshekpuk Quadrangle: Tracts 35-41, 81-85.

These geographical locations correspond to OCS development in the general offshore vicinity of Barrow, Prudhoe Bay, and Camden Bay. In each case, it is assumed that the oil and gas will be brought directly to shore by pipeline and then piped overland to Prudhoe Bay for interconnection with existing transportation corridors.

Examination of the selected tract areas indicates a range of possible distances from the producing wells to the shoreline, and from the point of arrival onshore to the Prudhoe Bay interconnection:

Range of Distances Kilometers (miles)

	West	Central	East
Offshore	5-32 (3-20)	11-34 (7-21)	5-19 (3-12)
Onshore	240-290 (150-180)	35-48 (22-30)	145 (90)

In subsequent analysis of pipeline costs, these ranges of distances are reduced to a single “average” value corresponding to a presumed center of the producing fields. These average values are as follows:

Average Distances Employed in Calculations Kilometers (miles)

	West	Central	East
Offshore	24 (15)	16 (10)	16 (10)
Onshore	274 (170)	39 (24)	145 (90)

2.2.5 Initial Set of Scenarios

The initial set of scenarios can be inferred from the 15 unique combinations of five building blocks and three geographical locations. Another scenario, that of exploration without subsequent development, can also be added. This set of scenarios now stands at the "skeletal" stage and further elaboration will follow the development of technical and economic assumptions in the next two sections.

Initial Scenarios

Location	Building Blocks (Oil, Billions of Barrels)				
East	3.5	2.3	1.4	0.7	0.4
Central	3.5	2.3	1.4	0.7	0.4
West	3.5	2.3	1.4	0.7	0.4

2.3 TECHNICAL ASSUMPTIONS

This section presents a synopsis of the major technological, developmental and operational assumptions used in the elaboration of the final scenarios, as well as in the establishment of investment requirements and time schedules for each scenario. Many of the assumptions have been drawn directly from the onshore technical parameters of the Sadlerochit formation near Prudhoe Bay*, and from the recent experiences in OCS petroleum exploration in the southern Canadian Beaufort Sea. Most of the technical references are described in Section 2.4.

Implic t in the scheduling assumptions are two overriding considerations 1) the manpower schedules refer to primary jobs rather than the number of men actually required; the latter can be estimated by the multiplication factors provided in Section 4.3 which more accurately reflects rotation schedules and the Arctic working conditions, and 2) the task development scheduling is the most optimistic available, and does not reflect the realities of potential, procedural, and political delays.

2.3.1 Tracts

The assumed number of tracts purchased, explored and ultimately held for production are shown in Table 2-3. These correspond to the five levels of scenarios resource, as well as two levels of anticipation surrounding the possible discovery of oil. The latter reflects two levels of hypothetical optimism that are generated by North Slope petroleum activities and knowledge of the offshore geologic structures at the time of the lease-sale.

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*It is recognized that the possibility exists that commercial oil and gas resources may be encountered in non-Sadlerochit reservoirs such as the Pennsylvanian-Mississippian Lisburne Group and Cretaceus Kuparuk formation or younger Tertiary strata which may have different reservoir characteristics and hydrocarbon properties. However, the scope of this study did not include a detailed geologic evaluation of Beaufort Sea oil and gas resources nor was warranted since it is anticipated that a significant portion of offshore Beaufort petroleum resources will probably be encountered in Permo-Triassic (Sadlerochit) reservoirs. Further, without a detailed geologic assessment a non-Sadlerochit reservoir model cannot be confidently formulated.

TABLE 2-3

ASSUMED NUMBER OF TRACTS PURCHASED AND DEVELOPED

Reserve Level Building Blocks (Billions of Barrels)	Anticipation of Discovery	Number of Tracts Purchased	Explored	Held
3.5	High	60	40	20
2.3	High	60	40	16
	Low	40	20	12
1.4	High	25	16	8
	Low	15	12	8
0.7	High	20	10	3
	Low	6	4	2
0.4	High	20	8	2
	Low	6	4	2
0	High	30-40	4	0
	Low	6	2	0

It should be noted that the number of tracts shown in the table are independent of the three specific scenario locations; they correspond only to the size of the scenario resources. In later analysis, when resource levels and locations are matched, they will be placed <u>within</u> the general tract locations as shown in Section 2.2.4.

An area about two to five times the productive area can normally be expected to be bid and sold. Not all of the purchased tracts will require exploration since the absence of petroleum in a significant structural feature would preclude the need to explore the drainage portion in a contiguous tract.

An alternate assumption of greater number of leases sold can be made, but it is unlikely that greater exploration would be sustained without a proportionate increase in the discovery of resources. As a maximum exploration impact case, it could be assumed that discovery anticipation in adjacent state waters or lands might unduly stimulate exploratory drilling in federal waters, without resultant discovery, leading to maximum exploratory “boom & bust” impacts.

2.3.2 <u>Ultimate Recovery</u>

Ultimate recovery of the reserves occurs at the point at which the operating costs for the driving mechanism, well maintenance, and field staffing exceed the value of the oil produced. Because the field is producing at a low rate at that point in time, errors of a few years in the cutoff date make little difference in the ultimate recovery for scenario purposes.

The utlimate recovery from a field is a function of the “fill factor” (average geographic density of petroleum reserves expressed in barrels per acre) and the “well spacing” (drainage area) at a given reservoir depth. The fill factor is assumed to be about 50,000 barrels per acre. This figure is consistent with that of the Sadlerochit formation (H.K. van Poollen and Associates, Inc., 1976) and with the value of 56,750 barrels per acre, the average U.S. fill factor for giant fields, as quoted in a recent study of U.S. OCS potential (A.D. Little Associates, Inc., 1976).

The assumed well spacing is 65 hectares (150 acres), (H.K. van Poollen and Associates, Inc., 1976), a figure consistent with the present well spacing at Prudhoe Bay. Since wells may be directionally drilled from stable platforms at an angle of 45° to 50° from the vertical, a considerable area of formation may be covered from a single platform location with 160-acre spacing. The typical depth of the Sadlerochit oil layers is about 2,700 m (9,000 feet), and an average depth of 3,050 (10,000 feet) is assumed for OCS petroleum formations. For 160-acre spacing, a 45° cone will permit 11 wells to be drilled from a single point to a formation 1,520 m (5,000 feet) deep, and about 45 wells to a formation 3,050m (10,000 feet) deep.

Given the fill factor and the average well spacing, the ultimate recovery per well can be calculated as follows:

Ultimate Recovery = Fill Factor x Well Spacing
= 50,000 bbl/acre x 160 acres/well
= 8 million bbl/well

Dividing the estimated reserves for each building block by the ultimate recovery per well will yield the number of producing wells required. For example, the 3.5 billion barrel reserve level will require 440 producing well:

Production Wells = Reserves ÷ Ultimate Recovery per well

= 3.5 Bbbl ÷ 8 mmbbl/well*

= 440 wells (with upward rounding)

Consequently, the figures assumed for subsequent analysis are as follows:

Building Blocks	Production Wells
3.5 Bbbl	440
2.3 Bbbl	295
1.4 Bbbl	180
0.7 Bbbl	90
0.4 Bbbl	50

2.3.3 Recovery Schedule

Even with the supplemental forcing of oil into producing wells by a gas or water drive, the rate of oil flow from a well will decline as the amount of recoverable oil in place diminishes. The recovery profile assumed in the analysis is shown in Table 2-4. It is typical of a field with water drive and some gas production for sale. The pattern is based

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*Abbreviations: bbl = barrel
mmbbl = millions of barrels
Bbbl = billions of barrels

TABLE 2-4

Assumed Production Profile

(percent of nominal daily maximum yield)

Year		Oil	Gas
1		50%	0%
2		95%	0%
3		95%	100%
4		95%	100% ± (small variation)
5		95%	100% ± "
6		95%	100% ± "
7		95%	100% ± "
8		75%	100% ± "
9		55%	100% ± "
10		45%	100% ± "
11		35%	100% ± "
12		30%	100% ± "
13		25%	100% ± "
14		20%	100% ± "
15		15%	100% ± "
16		10%	100% ± "
17		10%	100% ± "
18		10%	100% ± "
19		8%	100% ± "
20		6%	100% ± "
	Cumulative	964%	1,800%
	Average	48.2%	90%

Source: H.K. van Poollen and Associates, Inc., 1976 upon studies of the Sadlerochit reservoir by H.K. van Poollen Associates for the State of Alaska, Department of Natural Resources ("Prediction of Reservoir Fluid Recovery, Sadlerochit Formation, Prudhoe Bay Field", January, 1976).

The assumed profile is one of 29 depicted by H.K. van Poollen Associates and was selected for three reasons: 1) it provided a good revenue stream over time, 2) it had a flat gas recovery curve, and 3) it provided for a optimum BTU (British Thermal Unit) recovery (oil plus gas).

The assumed recovery schedule (production profile) indicates that oil production will rise to a maximum flow rate by the beginning of the second year and will remain at that level for six years, after which it will fall off exponentially. The average rate over the 20-year period will be 48 percent of the maximum flow rate. The maximum rate for any given building block can be calculated in the following manner:

$$\text{Maximum flow rate per day} = \frac{\text{Reserve Size}}{(.48)(20\ \text{years})(365\ \text{day/year})}$$

For gas, the effective average flow rate is 100 percent of the maximum for 18 years, beginning in the third year of field operation. Therefore, the maximum flow rates for each of the building blocks is as follows:

	Maximum Flow Rate Per Day*	
Building Block	Oil (MMBD)	Gas (bcfd)**
3.5	1.1	1.3 (1.26 rounded)
2.3	0.7	0.9
1.4	0.4	0.46
0.7	0.2	0.3
0.4	0.1	0.15

The maximum flow rate per well averages 2,500 barrels of oil per day for all building blocks, which is dictated by using an average production profile as fixed for all wells. This figure can be calculated by dividing the maximum output for each building block above the corresponding number of production wells as shown in Section 2.3.2, For example, the 3.5 billion barrel case yields:

$$\text{Maximum flow rate per well/per day} = \frac{\text{Maximum Flow Rate Per Day}}{\text{Number of Production Wells}}$$

$$= \frac{\text{1.1 MMBD}}{\text{440 Wells}}$$

$$= \text{2,500 barrels/day/well} ,$$

2.3.4 Wells and Platforms

Exploratory drilling is subject to OCS lease sale regulations requiring proof of reserves within five years. For the purposes of the scenarios, discovery is presumed to take place within this time constraint even though the exploratory activity itself may well continue beyond the

---

* MMBD = millions of barrels per day
bcfd = billions of cubic feet per day

** As indicated in Section 3.4.1 there is the possibility that OCS gas production may be delayed and for a time may not be produced contemporaneously with oil.

initial five-year period. Given the hypothetical discovery sites, most of exploratory drilling will take place within the land-fast ice zone and will be performed on temporary islands constructed of gravel, sand, reinforced soil, or ice, as well as from drillships and mobile rigs will remain inoperative (frozen in) during the long period of winter ice, the required year-round payment of a base charge will adversely affect the economics of their use. In constrast, temporary soil islands are relatively independent of weather (ice islands are not unless preserved artificially during the summer season), and therefore exploratory drilling is assumed to proceed on a year-round basis. Gravel/soil islands are more expensive than ice, which will tend to restrict their use to the near-shore waters and to areas where the chances appear favorable for transformation to a permanent island during the production phase. It has been assumed, for economic reasons, that no monopods will be used for exploratory drilling (although they are assumed for production drilling).

Gravel is presumed to be a limited resource in the Alaskan Beaufort region, and large quantities will be required for road and pad cover (see following section on equipment and material requirements). Moreover, the availability of gravel will become increasingly critical as one moves from the eastern Beaufort to the western Beaufort regions. As a result, more ice islands and fewer gravel islands are assumed as exploratory platforms in the central and western scenarios than in the eastern. The actual use of soil platform structures will depend upon the dredging potential in the offshore Beaufort waters; however, for the purposes of the scenarios, their use has been included in the economic analysis.

For the purposes of costing the scenarios in the next chapter, exploratory platforms are assumed to include a mix of gravel/soil islands, ice islands, and mobile rigs. Approximately 20 percent of the exploratory platforms are assumed to be composed of gravel, and 40 percent to 60 percent of ice.

Production platforms have been assumed to be gravel/soil islands and gravity structures (monopods); ice islands are by their very nature temporary. In the eastern Beaufort, where gravel availability is greatest, gravel islands would be the logical choice; however, this is in part offset by the fact that the waters in the eastern Beaufort get deeper much more quickly, requiring progressively greater volumes of gravel. In the western Beaufort, gravel is limited, and the ice exposure is potentially greater due to the fact that the maximum encroachment of the polar ice pack occurs shoreward of the 20-meter (60-foot) isobath between Cape Halkett and Point Barrow. Gravity structures may be the preferred production platform in these waters. Overall, if dredging of the Beaufort waters proves questionable, then gravity structures (e.g. monopods) will probably be used exclusively in the western and central Beaufort regions. For the purposes of costing the scenarios, a production platform mix of 70 percent gravity structures and 30 percent gravel islands has been used throughout.

Construction of exploratory islands [about 1.6 hectares (4 acres)] will require about 2 to 4 months (the latter figure is used for scheduling manpower), and it is assumed that there will be one platform per tract explored. Anywhere from 1 to 5 exploratory wells per platform is assumed to be the likely practice given the high cost of island construction; thus the statistical average of 2.5 exploratory wells per platform has been used for the purposes of economic analysis. Drilling is assumed to be scheduled one well at a time, requiring 90 days for each drilling.

Production islands will encompass nearly twice the area of the exploratory platforms [about 3 hectares (7 acres)] and construction time is estimated at about 4 months. It is also estimated that 3 or 4 production platforms will be required per large field, 2 platforms per medium field, and 1 or 2 platforms per small field. Between 20 and 50 producing wells will be located on each production platform. The average number of production wells per platform for groups of fields is shown below; the increase in wells per platform reflects an economic assumption that the smaller fields may not be developable unless the resources can be reached with more efficient platform utilization. In addition, 2 delineation wells were assumed per field, as well as one water-injection well for every 7-8 production wells. A delineation well is a dry hole marking the edge of the reservoir. Development wells (water wells and delineation wells) and production wells will be drilled two at a time, requiring 60 days per drilling.

Building Block	Average Number of Production Wells Per Platform
3.5 Bbbl	37
2.3 Bbbl	37
1.4 Bbbl	38-40
0.7 Bbbl	45
0.4 Bbbl	50

Since the Federal OCS lands are at least 4.8 km (3 miles) from the shoreline, and at places could be more than 24 km (15 miles) offshore while still remaining within the 20-meter (60-foot) isobath, field operations are likely to be performed on the artificial island platforms. However, with gravity structures where space is at a greater premium, field operations are likely to be performed onshore.

A typical production platform would be constructed on-site, with the drilling rigs subsequently erected in modular fashion. Once the probability of blowout was minimized and just prior to production, the processing equipment would be barged in (or skidded in on ice runners) for interconnection. The platform would likely contain two clusters of producing wells, an oil/water separator, an oil processing plant, a gas plant for stripping the hydrogen sulfide and liquid condensates, a pump station, a turbine electric generator, a helicopter pad, and crew quarters. The source of motive power on the platform can be gas turbines or diesel-type generators. Some of the latter will operate on raw crude oil if diesel supply is not available.

Where an oil field may cross the 20 meter (60-foot) isobath, it is possible to connect a few on-bottom wells to a platform located in the shallower water. The technology barrier to this situation is the pipeline crossing of the Stamukhi zone, where the pack ice tends to gouge the bottom. The on-bottom wells may be constructed so that contact with the pack ice would cause them to shut in. The pipeline may locally have to be buried deeply to avoid the ice gouging.

2.3.5 Equipment and Materials

An indication of the equipment that might be required during petroleum exploration in the Alaskan Arctic OCS lease-sale area of the Beaufort Sea, if artificial islands were to be used, is provided by the current (1976) construction spread under contract to Imperial Oil in the southern Canadian Beaufort Sea (de Jong et. al., 1975):

- 24 inch cutter suction dredge
- 34 inch stationary suction dredge
- Two 2,000 cu. yd. bottom dump barges
- Three 300 cu. yd. bottom dump barges
- Four 1,500 hp. tugs
- Two 600 h.p tugs
- One floating crane
- Four 6 cu. yd. clamshell cranes on spudded barges

- Barge loading pontoon
- Floating pipelines
- Floating camps and repair shop
- Sandbagging machines and
- Several other barges, launches and auxiliary equipment

2.3.5.1 <u>Well Specifications</u>

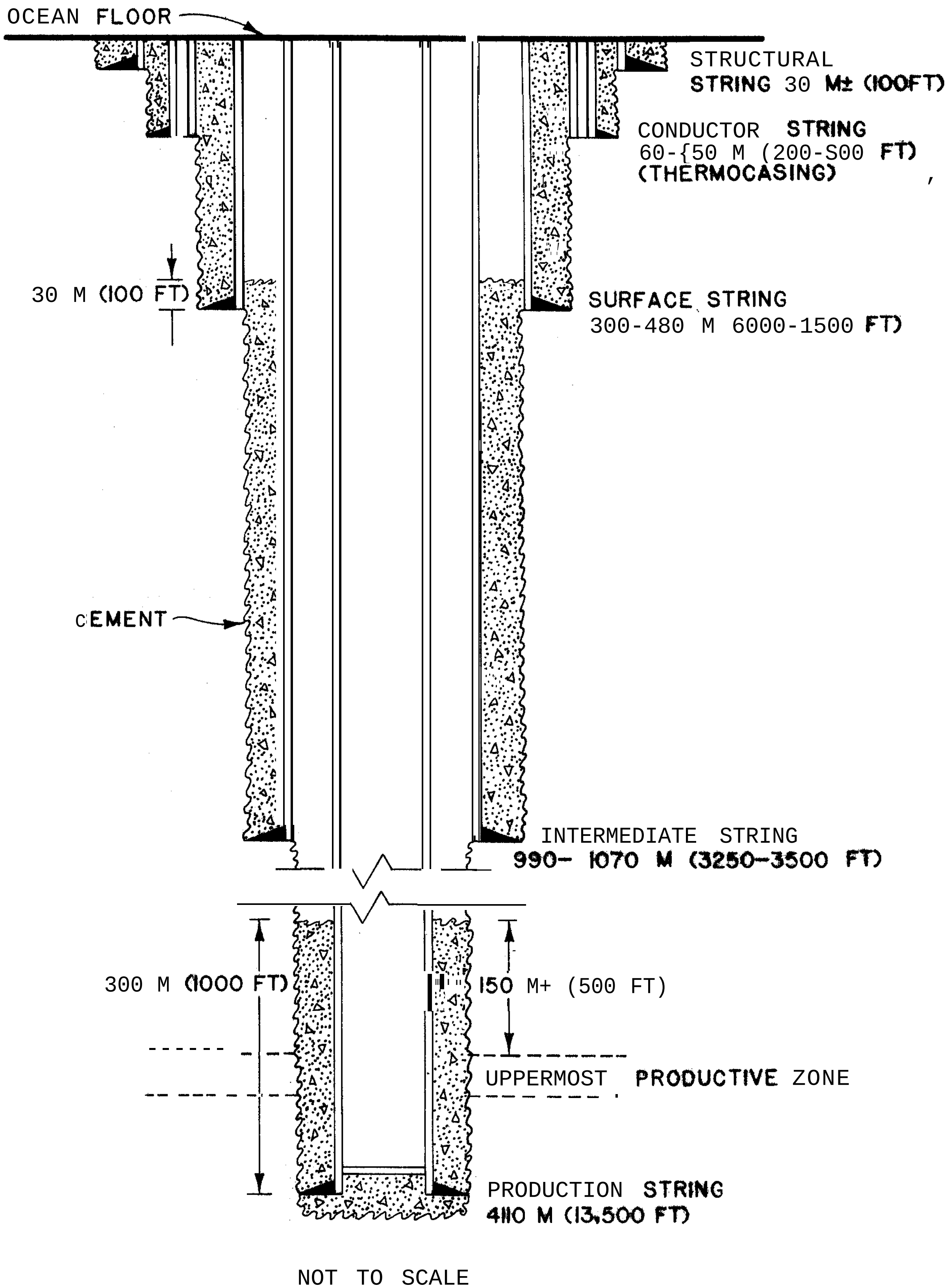
Offshore wells in the Beaufort Sea will be directionally drilled to an average depth of 3,050 m (10,000 feet). Such a well drilled at an average of 50° from the vertical would have an average length of 4,100 m (13,500 feet) over the field, and a maximum of about 4,570 m (15,000 feet).

Permafrost will be an important design consideration. To maintain the integrity of the well hole, a thermocasing string is assumed and used in the top 60-150 m (200 to 500 feet) of the hole. Thermocasing consists of an outer and inner casing between which is placed a layer of plastic insulation.

The casing program for a typical well is shown schematically in Figure 2-3 and includes five strings:

- Structural casing about 30 inches in diameter set at 30 m (100 feet) to provide stability in unconsolidated sediments;

- Thermocasing set at 60-150 m (200 to 500 feet) comprising an outer casing, which serves as the conductor string (20-inch), and an inner casing, which serves as a sleeve, with a plastic insulation between;



SCHEMATIC SKETCH

EXAMPLE OF 4,110 M (13,500 FT) WELL CASING PROGRAM

FIGURE 2-3

- 13-3/8 inch surface casing set at460m (1,500 feet);
- 9-5/8 inch intermediate casing set at 1,070 m (3,500 feet); and
- 7-inch production casing set below 1,070 m (3,500 feet).

2.3.5.2 Drilling Mud

Based upon the schematic well design in Figure 2-3, 138 cubic meters (180 cubic yards) of drilling mud will be required. This quantity would probably be the total required for one well and represents an inventory (reusable) of 124 cubic meters (162 cubic yards) and a consumption (loss) of 14 cubic meters (18 cubic yards).

2.3.5.3 Drill Cuttings

Based upon the schematic well design shown in Figure 2-3, the volume of cuttings produced would be approximately 206 cubic meters (270 cubic yards). The drill cuttings may be separated from the mud by screens and discharged at the drill site.

2.3.5.4 Grout (Cement)

Based upon the schematic well design shown in Figure 2-3, the volume of grout (cement) required per well is about 106 cubic meters (142 cubic yards) or 152 tons.

2.3.5.5 Water

Water will be required for drilling the well, equipment operation, camp operation and human consumption. It is assumed that most of the water for drilling the well will be salt water taken from the sea. However, some fresh water will be required for some mud and cement chemistry.

potable water for camp operation and human consumption is generally estimated at 378 l/man/day (100 gal./man/day) (Department of the Navy, 1977) although Alyeska experience indicates a 265 l/man/day (70 gal./man/day) average (Eggener, 1977). Assuming a 90-day construction period utilizing 40 men to build an artificial island, total fresh water requirements will be about 1,360,000 l (360,000 gallons) or 8,000 bbl. Allowing 90 days per well with a drilling crew of 40, fresh water consumption will be 1,360,000 1 (360,000 gallons) or8,000 bbl.

2.3.5.6 Gravel

For the purposes of estimating gravel requirements, it is assumed that some of the exploratory and production wells will be drilled from an artificial island built of gravel. The quantity of gravel required per well offshore is much greater than a conventional drill pad for an onshore exploratory well of 11,470 cubic meters (15,000 cubic yards) (Alaska Oil and Gas Association, 1975a).

Table 2-5 provides estimates of gravel requirements for offshore exploratory and production islands and other petroleum-related facilities.

Gravel will be acquired through both dredging offshore and borrow sites onshore.

2.3.5.7 Fuel

Fuel requirements of a typical well are estimated at 9,000 bbl., most of which is comprised of Arctic diesel fuel, and includes operation of such equipment as dredges, work barges, cranes and service boats.

TABLE 2-5

SUMMARY OF GRAVEL REQUIREMENTS

Exploratory Island (1.2 hectares or) (3 acres)*	154,143 cubic meters (201,600 cubic yards)
Production Island (2.8 hectares or) (7 acres)*	137,688 cubic meters (451,733 cubic yards)
Pipeline Work Pad	15,.201 cubic meters/km (32,000 cubic yards/mile)
Pipeline Access Road	26,127 cubic meters/km (55,000 cubic yards/mile)

*Assumes an average water depth of 10 m (30 feet) and freeboard of 3 m (10 feet).

Reference: Alaska Oil and Gas Association, 1975a.

2.3.5.8 Waste Disposal

In addition to the cutting and mud volumes indicated above, there will be solid waste generation estimated at about 4.5 kg per capita per day (10 pounds per capita per day). Water usage and thus domestic wastewater discharge can be expected to be about 378 1 per capita per day (loo gallons per capita per day) (Eggener, 1977).

Disposal of these wastes will follow applicable state and federal regulations. Domestic wastewater will probably be treated to secondary standards before discharge into the sea. Solid wastes will probably be separated into combustible and non-combustible materials with the combustible disposed of by incineration. Non-combustibles will be taken to an approved sanitary landfill.

Drill cuttings, separated from the mud, will probably be discharged on to the sea floor if regulations permit. Drill mud is generally recycled to drill other wells, although eventual disposal may be either in the sea or to on-land disposal sites depending upon state or federal regulations.

2.3.6 Processing and Maintenance

2.3.6.1 Processing

The scenarios presume the location of the petroleum fluids processing facilities to be on the production platforms. Complete assembly is scheduled to take one year, and to be typically undertaken just prior to production.

An efficient oil processing unit developed in the Prudhoe Bay field has been estimated at 300,000 barrels per day. A production platform containing

20 to 50 wells would have an initial average flow rate of 2,500 barrels per day per well. The resulting maximum platform throughputs of 125,000 barrels per day offer some incentive to combine the processing functions of several platforms wherever feasible.

2.3.6.2 Maintenance

During the life of the well, it is sometimes necessary to place tools or chemicals into the well to remove sand or corrosion to increase the perforations that allow oil to enter the casing, to repair the cementing, etc. These procedures are performed from workover platforms, with the tools generally operated by wireline instead of rotating drill stem. Well maintenance downtime in the scenario projections is absorbed into the production figures, which are presumed to be net of downtime. The workover employment is averaged into the total field production employment. However, workover may involve specialized crews who are imported only for the particular maintenance procedures.

During the draining of the field, additional wells may be placed in the field, reducing the well spacing at certain locations to improve the recovery. In a water flood program, for example, additional wells may be inserted to increase the bottom pressure of the reservoir drive. The cost and employment figures for wells of this type have also been averaged into the operating costs of the field.

2.3.7 Pipeline Specifications

This section briefly describes the pipeline specifications for each of the various reserve levels with respect to the three geographical locations

(Tables 2-6 through 2-13). The pipeline distances given are the most direct offshore and onshore links from the hypothetical oil fields (east, central and west regions) to the existing Prudhoe Bay facilities (TAPS terminal). The average offshore distances assumed (see Section 2.2.4) multiplied by the average number of offshore pipeline corridors (as shown in the following tables) yields the total offshore kilometers of gathering line between the oil fields and shore. Two options are indicated for transporting oil to shore. Multiple pipelines could transport the oil to shore in several separate corridors. Alternately, a single trunk pipeline in one corridor could be utilized, assuming that the oil is first gathered through short lines to a single offshore platform or island. The onshore pipeline routing presumes the immediate convergence of the offshore lines into a single onshore feeder line to the TAPS terminal.

An alternative to conventional trunk pipelines is a series of small diameter (12 to 14 inches) flexible pipelines which can be transported and laid from spools on a barge. Several 12-inch lines laid parallel in the same trench could replace a single larger diameter trunk line.

The offshore platforms must be connected to the land by pipelines which pass through the bottom-fast ice zone, and which may come in contact with ice-bonded permafrost in burial, Experience in this technology may be gained in the state offshore lands before it has to be solved for federal OCS leases. The principal technical problem is to make an insulated trench suffice in areas of sub-sea ice-rich permafrost, since

TABLE 2-6

Oil Pipeline Specifications

Field Reserves Bbbl	Nominal Capacity mmbd	A. Onshore and offshore		B. Offshore	
		Single Line Diameter (inches)		No. of 12″ Lines	
		8 kph (5 mph)	11 kph (7 mph)	11 kph (7 mph)	16 kph (10 mph)
3.5*	1.1	42	36	9	7
2.3*	0.7	34	30	6	4
1.4	0.45	28	24	4	3
0.7*	0.2	18	16	2	1
0.4	0.1	14	12	1	1

*Scenario Selected

TABLE 2-7

Eastern Region--Offshore Oil Pipeline Construction

By Field Size Estimates

	Multiple Pipeline Option				Trunk Pipeline Option		
Field Size Oil, Bbbl	No. of Corridors	Total Corridor Kilometers (miles)	No. of 12" Pipelines[2] 11 kph (7 mph)	No. of 12" Pipelines[2] 16 kph (10 mph)	Trunk Pipeline[1] Diameter (inches) One 16 km (10 mi.) Corridor	Excavation Volume/Mile cubic meters/km (cu.yds./mi)	Possible Burial Depth m (ft.)
3, 5**	7	113 (70)	9	7	42 36	7,152 (15,057) 5,341 (11 ,244)	2.4 (8)
2. 3**	4	64 (40)	6	4	34 30	5,016 (10,560) 4,598 (9,680)	" (")
1.4	4	64 (40)	4	3	28 24	4,366 (9,190) 3,901 (8,213)	" (")
0. 7**	2	32 (20)	2	1	18 16	3,251 (6,844) 3,065 (6,453)	" (")
0.4	2	32 (20)	1	1	14 12	2,880 (6,062) 2,647 (5,573)	" (")

1--See Table 4-2
2--See Table 4-2
**Scenario selected

TABLE 2-8

Central Region--Offshore Oil Pipeline Construction

By Field Size Estimates

	Multiple Pipeline Option				Trunk Pipeline Option		
Field Size Oil, Bbbl	No. of Corridors	Total Corridor Kilometers (miles)	No. of 12" Pipelines[2] 11 kph (7 mph)	No. of 12" Pipelines[2] 16 kph (10 mph)	Trunk Pipeline[1] Diameter (inches) One 16 km (10 mi.) Corridor	Excavation Volume/Mile cubic meters/ km (cu.yds./mi)	Possible Burial Depth m (ft.)
3, 5**	7	113 (70)	9	7	42 36	7,152 (15,057) 5,341 (11,244)	2.4 (8)
2. 3**	4'	64 (40)	6	4	34 30	5,016 (10,560) 4,598 (9,680)	" (")
1.4	2	32 (20)	4	3	28 24	4,366 (9,190) 3,901 (8,213)	" (")
0. 7**	2	32 (20)	2	1	18 16	3,251 (6,844) 3,065 (6,453)	" (")
0.4	2	32 (20)	1	1	14 12	2,880 (6,062) 2,647 (5,573)	" (")

1--See Table 4-2
2--See Table 4-2
**Scenario selected

TABLE 2-9

Western Region--Offshore Oil Pipeline Construction

By Field Size Estimates

	Multiple Pipeline Option				Trunk Pipeline Option		
Field Size Oil , Bbbl	No. of Corridors	Total Corridor Kilometers (miles)	No. of 12" Pipelines[2] 11 kph (7 mph)	No. of 12" Pipelines[2] 16 kph (10 mph)	Trunk Pipeline[1] Diameter (inches) One 24 km (15 mi.) Corridor	Excavation Volume/Mile cubic meters/ km (cu.yds./mi)	Possible Burial Depth m (ft.)
3. 5**	7	169 (105)	9	7	42 36	7,152 (15,057) 5,341 (11 ,244)	2.4 (8)
2.3**	4	97 (60)	4	4	34 30	5,016 (10,560) 4,598 (9,680)	" (")
1.4	4	97 (60)	4	3	28 24	4,366 (9,190) 3,901 (8,213)	" (")
0. 7**	2	32 (20)	2	1	18 16	3,251 (6,844) 3,065 (6,453)	" (")
0.4	2	32 (20)	1	1	14 12	2,880 (6,062) 2,647 (5,573)	" (")

1--See Table 4-2
2--See Table 4-2
**Scenario selected

TABLE 2-10

Eastern Oil Pipel Construction By Field Sizes

Assuming Link to Existing TAPS Corridor at

Field Reserves Bbbl	Pipeline Diameter (inches)	Kilometers (Mi.) of Pipeline (A)	No. of Pump Stations	Typical Burial Depth m (ft.)	Gravel Vol. Road (B) cu. meters/km (cu. yds./mi.)	Gravel Vol. Work Pad (C) cu. meters/km (cu. yds./mi.)	Volume Gravel Required for Pipeline (A x B + C) cu. meters (cu. yds.)	Excavation* Vol. cu. meters/km (cu. yds./mi.
3.5**	42 36	145 (90)	0	1 (3)	26,127 (55,000)	15,201 (32,000)	3,986,818 (7,[illegible])	3,577 (7,528) 3,019 (6,355)
2.3**	34 30	" (")	"	" (")	"	"	"	2,844 (5,985) 2,509 (5,280)
1.4	28 24	" (")	"	" (")	"	"	"	2,348 (4,942) 2,044 (4,302)
0.7**	18 16	" (")	"	" (")	"	"	"	1,626 (3,422) 1,497 (3,150)
0.4	14 12	" (")	"	" (")	"	"	"	1,372 (2,888) 1,254 (2,640)

*Note: Hot oil pipeline will probably be above ground for the most part. Only applicable for below ground sections such as thaw-stable soil areas and major river crossings.

**Scenario selected.

TABLE 2-1 ?

Central Region--Onshore Oil Pipeline Construction By Field Sizes

Assuming Link to Existing TAPS Corridor at Prudhoe Bay

Field Reserves Bbbl	Pipeline Diameter (inches)	Kilometers (Mi.) of Pipeline (A)	No. of Pump Stations	Typical Burial Depth m (ft.)	Gravel Vol. Road (B) cu. meters/km (cu. yds./mi.)	Gravel Vol. Work Pad (C) cu. meters/km (cu. yds./mi.)	Volume Gravel Required for Pipeline (A x B + C) cu. meters (CU. yds.)	Excavation* Vol. cu. meters/km (cu. yds./mi.)
3, 5**	42 36	39 (24)	0	1 (3)	26,127 (55,000)	15,201 (32,000)	1,596,485 (2,088,000)	3,577 (7,528) 3,019 (6,355)
2. 3**	34 30	" (") (")	"	" (")	"	"	"	2,844 (5,985) 2,509 (5,280)
1.4	28 24	" (")	"	" (")	"	"	"	2,348 (4,942) 2,044 (4,302)
0. 7**	18 16	" ("	"	" (")	"	"	"	1,626 (3,422) 1,497 (3,150)
0.4	14 12	" (")	"	" (")	"	"	"	1,372 (2,888) 1,254 (2,640)

*Note: Hot oil pipeline will probably be above ground for the most part. Only applicable for below ground sections such as thaw-stable soi 1 areas and major river crossings.

**Scenario selected.

TABLE 2-12

Western Region--Onshore Oil Pipeline Construction By Field Sizes

Assuming Link to Existing TAPS Corridor at Prudhoe Bay

Field Reserves Bbbl	Pipeline Diameter (inches)	Kilometers (Mi.) of Pipeline (A)	No. of Pump Stations	Typical Burial Depth m (ft.)	Gravel Vol. Road (B) cu. meters/km (cu. yds./mi.)	Gravel Vol. Work Pad (C) cu. meters/km (cu. yds./mi.)	Volume Gravel Required for Pipeline (A x B + C) cu. meters (cu. yds.)	Excavation* Vol. cu. meters/km (cu. yds./mi.)
3.5**	42 36	274 (170)	0	1 (3)	26,127 (55,000)	15,201 (32,000)	1,308,434 (14,790,000]	3,577 (7,528) 3,019 (6,355)
2.3**	34 30	" (")	"	" (")	"	"	"	2,844 (5,985) 2,509 (5,280)
1.4	28 24	" (")	"	" (")	"	"	"	2,348 (4,942) 2,044 (4,302)
0.7**	18 16	" (")	"	" (")	"	"	"	1,626 (3,422) 1,497 (3,150)
0.4	14 12	" (")	"	" (")	"	"	"	1,372 (2,888) 1,254 (2,640)

*Note: Hot oil pipeline will probably be above ground for the most part. Only applicable for below ground sections such as thaw-stable soil areas and major river crossings.

**Scenario selected.

TABLE 2-13 GAS PIPELINE SPECIFICATIONS-ALL REGIONS

Gas Reserves tcf	Nominal Capacity bcfd	A. Onshore 322 km (200 mi.) compressor station spacing				B. Offshore 24 km (15 mi.) compressor station links	
		Single line diameter (inches) at pressure (psi)				No. of 12″ lines at pressure (psi)	
		600	800	1200	1800	200 (min.)	600 (min.)
8.8	1.3	52	45	38	32	5	4
4.5	0.9	44	40	34	28	4	3
3.5	0.5	36	32	26	22	2	2
1.8	0.3	30	26	22	18	2	1
1	0.15	22	20	18	13	1	1

it is doubtful that refrigerating radiators, such as those used on the Alyeska project, can survive the occasional exposures of moving ice. In addition, burial depths will have to be sufficient to afford protection from ice scour.

The onshore hot-oil pipelines will probably be above ground, similar to Alyeska, except in areas of thaw stable soils and at major river crossings. It can be assumed that the construction and operational experience gained through the Alyeska pipeline, including environmental data, will influence the design and routing of subsequent North Slope pipelines. A discussion of pipeline technology and environmental constraints is provided in Section 1.3.6.

2.3.8 Onshore Facilities

2.3.8.1 Overview

The onshore facilities will consist primarily of a harbor and base camp, as well as a terminal yard to stack all of the required tubular goods and mobile equipment (tractors, trucks, etc.). Because of the shallow Beaufort Sea waters, the harbor is not likely to be a natural one. It is assumed to be a dredged harbor located some distance from shore, surrounded by a protective berm, and connected to the shore by a gravel causeway. Adjoining the protective berm would be a ramp to permit the movement of tractors and trucks onto and off the winter ice. The base camp would contain adequate housing for the construction crews, operational personnel and support staff, off duty platform personnel, and temporary technicians and visitors. It will also contain warehousing space, machinery maintenance and repair shops, office space, and fuel and water storage tanks.

In the general vicinity of the base camp there will also be a helicopter pad to assist in the movement of personnel and supplies to the platforms during periods of inclement weather or during the transitional periods between open water and winter ice. Similarly, a gravel or snow strip will be required to permit the use of fixed wing aircraft.

Other requirements include an onshore dump for waste materials, a water source with appropriate plumbing connections, and a gravel dump. The latter might be connected by a mechanical conveyor system if the borrow site is within a reasonable distance. Gravel roads will be required for all logistical interconnections in the base camp area to protect the permafrost from the movements of men and machinery.

2.3.8.2 Exploratory Base Camps

Depending upon the magnitude of the exploration program, base camps could approach the size of a development/production camp, or could be very modest. High investment costs would normally favor a minimal level of development or the use of existing facilities. Basic options are discussed below.

2.3.8.2.1 Airlift Base Camps

The most likely form of base camp for exploration would entail the use of air transport for delivery of equipment and supplies. The camp would include the following basic facilities:

- An airstrip of approximately 6,000 feet in length, constructed of gravel, or snow for winter onshore usage.

- Nearby outdoor storage of fuel bladders and drilling supplies such as mud sacks, cement and well casings.

- Temporary buildings constructed on gravel pads for crew, operations and maintenance.

- Outdoor storage of construction equipment for construction of ice islands or gravel islands. It is assumed that all initial exploration will take place from ice and gravel islands, or from mobile rigs in the open-water season. Storage space will be required for such equipment as pumps and plows.

2.3.8.2.2 Barge-Serviced Base Camps

A barge-serviced base camp could be necessary if significant quantities of heavy cargo were required for exploration. Such cargo could include more permanent buildings, or trucks for hauling gravel associated with the construction of gravel islands. Although barge service may only be available for a short period during the summer months, it is the most economical and practical means of transporting heavy equipment and bulk cargo.

An existing harbor sheltered from the effects of pack ice pressures would have to be utilized. For a small operation, a barge carrying all necessary crew quarters, storage facilities, communications and other equipment could be utilized, obviating the need for major land-based construction. An airstrip could be constructed on the ice for winter exploration operations.

2.3.8.2.3 Utilization of Existing Infrastructure

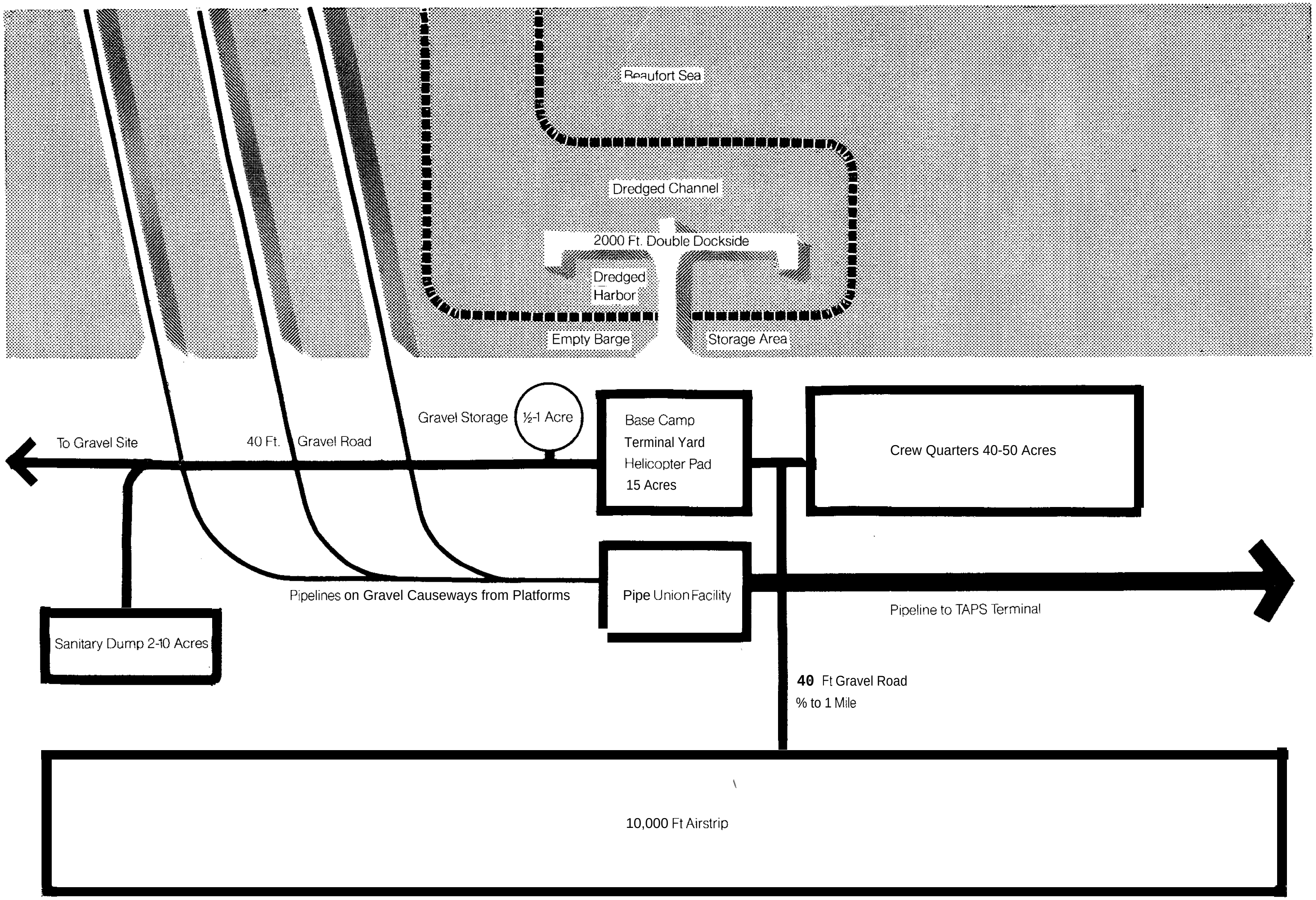
Existing airstrips would be preferred, if they were in proximity to the offshore exploration area. Existing paved airstrips include the Barrow Wiley Post Airfield; the Naval Arctic Research Laboratory Airstrip; the NPR-A Airstrips at the Deactivated DEW line Station on Cape Simpson and the operating DEW line strip at Lonely; Prudhoe Bay; and the Kaktovik DEW line strip. Preference would also be given to those locations where additional infrastructure existed, such as storage facilities, labor supply, and other support facilities.

With respect to barge-service base camps, protected harbors exist at Barrow (NARL), Lonely, Prudhoe Bay and Kaktovik.

A more complete description of the existing ports and infrastructure on the North Slope is provided in Section 4.1.2.

2.3.8.3 Production Base Camps

A typical development and production base camp would have significantly greater and more permanent services and facilities than those required ‘for exploration. An exploration camp could be expanded to accommodate development and production, or a new production base camp could be built in closer proximity to the actual offshore development fields. Basic requirements for a prototypical port development/production camp are illustrated on Figure 2-4, and are discussed below:



Probable Port Development Base Camp

Figure 2-4

2.3.8.3.1 Dredged Harbor

A barge channel and harbor could be dredged to accommodate medium draft sea barges [6 m (20 feet) dock-side depth at low tide]. Some of this dredged material could be used for construction of artificial islands. The harbor would be sufficient in size [approximately 10 hectares (25 acres)] to accommodate up to forty ocean-going barges. Barges would be unloaded and then floated to an undredged area near the shoreline.

2.3.8.3.2 Dock-Causeway

Dredged fill material would be used to construct a dock-causeway of approximately 1,220 m (4,000 feet) in length. A “T’’-shaped double-sided dock is illustrated in Figure 2-4; but actual configuration may vary depending upon channel and harbor dredging requirements and site-specific sea ice conditions. It is important for the causeway to be designed such that iced-in barges are protected from pressures of sea ice.

A ramp from the causeway could be provided for tractors to move on to the ice, carrying personnel and supplies to offshore platforms. Unloading of supplies would take place at quay side using skids pulled by tractors. A mobile crane could be required for unloading special equipment.

2.3.8.3.3 Terminal Yard

A marshalling area would be developed near the dock for storage of such drilling equipment as casing and drill pipe, bagged cement, powdered drilling mud, water and fuel, tractors, skids and other inactive storage. Base operation buildings would be constructed on gravel pads. A helicopter pad would be located nearby for use of helicopters in moving personnel and small equipment to platforms. Total area of the terminal yard is estimated at 6 hectares (15 acres).

2.3.8.3.4 Crew Quarters

Crew quarters, including kitchen and dining facilities, could be provided for up to 3,000 men in modular prefabricated buildings, elevated on piles. Providing two-man accommodations of personnel in two-story buildings is estimated to require a total area of 16 to 20 hectares (40 to 50 acres).

Liquid wastes would be collected and treated to secondary standards before discharge into the sea. Combustible solid wastes would be incinerated and non-combustibles taken to an approved sanitary landfill.

2.3.8.3.5 Airstrip

A gravel airstrip of between 1,830 to 3,050 m (6,000 and 10,000 feet) in length will be built within one to two kilometers (one half to one mile) of the base camp, served by a gravel road sufficient in width to carry trucks with heavy cargo. Buildings for aircraft and helicopter maintenance would be located adjacent to the strip.

2.3.8.4 Pipelines

Offshore pipelines from individual platforms or groups of platforms would normally be directed to landfalls near the production base camp. Pipelines carrying hot oil from the platforms would be buried in trenches in the sea bottom, to avoid effects of sea ice scour which could damage or rupture the pipe. In near-shore areas, subsea permafrost may be encountered. Because trenching through subsea permafrost may be difficult and costly, offshore pipelines may be carried on short causeways in these areas.

Pipelines could either be aligned independently according to the most direct linkages to the shore, or could follow close parallel alignment. A single causeway or group of causeways could presumably carry a number of pipelines to shore from various platform locations within the field.

At or near the production base camp, separate offshore pipelines would connect to a pipe union, or pipe marshaling facility. The oil collected at the facility would then be pumped through one or two larger pipelines to connect with Alyeska Pipeline at Prudhoe Bay. From there, the oil would be transported to Valdez. The hot oil pipelines would be elevated on vertical support members (VSM's) above gravel pads, except in limited areas of thaw-stable soils, where they would be buried to a depth of approximately 1 m (3 feet). A gravel or snow construction road would be built parallel to the pipelines. At major river crossings, the pipelines would normally be buried beneath the stream bed.

Gas pipelines will follow offshore alignments adjacent to oil pipelines, utilizing causeways to the shore. The separate gas lines will be directed to a gas plant for equalization of pressure and transport in a single, larger pipeline to Prudhoe Bay.

To maintain efficient disposition of men and material, industry may prefer that pipeline construction take place throughout the year. Offshore and onshore pipeline technology and related problems are discussed in Section 1.3.6 and scenario pipeline specifications are presented in Section 2.3.7.

2.3.9 Probability of Oil Spills

Given the unique conditions of the Beaufort Sea environment, spillage of oil is of particular concern. To place the problem in some perspective, the likelihood of such spills for each of the reserve level "building blocks" was calculated and presented in summary fashion in this section. The spillage probabilities were developed for three separate activities or kinds of exposure to spillage:

- Platform blowouts
- Platform spills
- Pipeline spills

2.3.9.1 Platform or Well Blowouts

The probability of a well blowout resulting in oil release in Beaufort Sea drilling operations has been projected as 0.01 percent per well in Canadian studies (Beaufort Sea Project, Environment Canada, Victoria, B.C., Final Reports, January 1976). However, the historical rate for all U.S. OCS experience has been about 0.035 percent per well. The U.S. parameter has been used as a high rate basis for projection, although the record is based mainly on Gulf of Mexico experience and includes gas blowouts with no oil release (Harris, Piper and McFarlane, 1977). The probability of oil release would be expected to be close to the Canadian projection.

The likelihood of platform blowouts has been presented in Table 2-14 for both rates, without differentiation as to mode (i.e., loss of formation integrity, procedural error in well control, loss of casing or equipment integrity) or output (gas, oil, water). The exposure basis for the blowout risk presented is the number of wells drilled.

2.3.9.2 Platform Spills

The historical experience of OCS petroleum development, primarily in the Gulf of Mexico, has been used to project the likelihood of platform spills in the Beaufort scenarios, although the ability for containment on artificial islands may be greater than for platform structures. The empirical evidence indicates an occurrence rate of 0.0175 spills per year per platform. Further, of these spills 75 percent occur with accidents (fire or injury), averaging 2,500 barrels each loss, and 25 percent do not involve accidents and lose about 1,100 barrels per event (U.S. Geological Survey, 1975). A weighted average of these two modes was applied to project an average platform spill loss of 2,136 barrels in Beaufort Sea platform spills. The number of spills which may occur in a 20-year period and the amount of oil annually spilled which are calculated from these parameters is shown in Table 2-15.

TABLE 2-14

WELL BLOWOUTS
(Probability of Having 0, 1, or 2 or more Blowouts in the field)

Field Size	High Estimate			Low Estimate Canadian Beaufort Sea	
	0	1	2 or more	0	1 or more
3.5 Bbbl	83%	15%	2%	95%	5%
2.3 Bbbl	87%	12%	1%	96%	4%
1.4 Bbbl	92%	8%	-.	97%	2%
0.7 Bbbl	90%	4%	--	99%	1%

Source: Dames and Moore

TABLE 2-15

PLATFORM SPILLS

Field Size	Number of Spills Over 20 Years	Annual Spillage (in Barrels)
3.5 Bbbl	4.2	449
2.3 Bbbl	2.8	299
1.4 Bbbl	1.4	150
.7 Bbbl	.7	75

Source: U.S. Geological Survey, 1975.

2.3.9.3 Pipeline Spills (Leaks)

The pipelines suggested by the scenarios are laid both onshore and offshore. The problems and likelihood of leaks onshore are quite different and less severe than those encountered offshore. The most critical concern of offshore pipelines is the multitude of issues raised by Beaufort Sea ice conditions. Dames & Moore has projected a rate of 50 ruptures/year/100,000 miles of pipeline for new U.S. systems, compared with a historical rate of about 120/year/100,000 miles for the existing crude oil network lines. (Environmental Assessment for the SEADOCK Offshore Oilport, Dames & Moore, Houston, Texas, 1975; Office of Pipeline Safety, Annual Summaries, Dept. of Interior, Washington, D.C.).

Each potential rupture means the loss of a certain amount of oil. The U.S. average is 1,100 bbl lost from each spill onshore. The offshore spillage is expected to average 300 bbl due to the higher level of technology (sensors, valves, etc.) built into the pipeline system and the small size of the pipes.

Table 2-16 presents the likelihood of ruptures occurring in the pipeline systems over a 20-year period (essentially the assumed rate of rupture times the number of miles of pipe over 20 years). The eastern and central areas are used for comparison and the annual amount of spillage is distributed into offshore and onshore components. As can be seen from the table, the spillage risk in pipeline system increases with system length.

Table 2-16

PIPELINE SPILLS (LEAKS)

Alternative Field Locations	Annual Spill Expectations (bbls) Onshore	Offshore	Probability of Spills Over 20 Years (%) 0	1	2	3 or more	Cumulative 1 or more
Central 3.5 Bbbl field	13 bbls	11 bbls	38.2	37.7	17.6	6.5	61.8
Eastern 3.5 Bbbl field	49 bbls	11 bbls	18.9	32.8	27.1	21.2	81.1
Central 2.3 Bbbl field	13 bbls	5 bbls	52.2	34.5	10.8	2.5	47.8
Eastern 2.3 Bbbl field	49 bbls	6 bbls	26.1	36.3	23.9	13.7	73.9
Central 1.4 Bbbl field	13 bbls	6 bbls	52.2	34.5	10.8	2.5	47.8
central 0.7 Bbbl field	13 bbls	5 bbls	57.8	32.1	8.5	1.6	42.2

The entire preceding discussion is one of probabilities, simply estimating the likelihood of any occurrence. This is not intended to demonstrate where spillage may occur, nor the exact amount or timing of any spill.

2.4 Scenario and Resource Literature

The economic and technical data contained in this report come from a variety of government and industry sources.

Data on equipment utilization, manpower usage and petroleum operation costs in Alaska includes published and unpublished information from Alyeska, Arctic gas and El Paso, In addition, there are about fifteen petroleum industry journals that provide baseline information on such subjects as production technology, petroleum geology, cost and production statistics. The Oil and Gas Journal, for example is the best current source of cost trends; and other publications, such as Petroleum Engineer, provide details on equipment performance and requirements. Several of these journals (e.g., Offshore and Ocean Industry) deal exclusively with marine and offshore activities, and provide equipment inventory and technology data against which the impacts of future operations can be projected. Petroleum economics, specifically baseline cost and facilities information, is covered in Oil and Gas Journal--Annual Summary of Pipeline Costs and the Oil and Gas Journal--Nelson Index which provides monthly baseline information on petroleum facilities costs.

Selected literature on Alaskan petroleum development relevant to this study and reviewed for this report includes:

0 <u>Outer Continental Shelf Oil and Gas Costs and Production Volume: Their Impact on the Nation's Energy Balance to 1990</u> (A. D. Little, Inc, 1976) is an unpublished report for the U.S. Bureau of Land Management which is one of the most important compilations of petroleum development scenarios. The report is an in-depth cost analysis of seventeen nationwide OCS lease areas including those in Alaska, and presents the costs of producing oil and gas, estimates of production under various price scenarios, and the impact of OCS production on national energy supply and demand.

o Petroleum development scenarios and impacts are discussed in <u>Onshore Impacts of Oil and Gas Development in Alaska</u> (Resource Planning Associates, 1974), which provides scenarios for onshore and offshore frontier areas of Alaska including the Beaufort Sea and projects the socioeconomic and environmental impacts at the state, regions"l and community levels. The analysis assumes sequential offshore development of each OCS lease area in the state and presents a cumulative impact analysis.

o Onshore petroleum development scenarios are projected for Naval Petroleum Reserve No. 4 (National Petroleum Reserve - Alaska) in <u>The Exploration, Development and Production of Naval Petroleum No. 4</u> (Resource Planning Associates, 1976). This report discusses alternative management programs (private vs.

government) for exploration, development and production of NPR-4. New (lower) estimates of the oil and gas resource potential of NPR-4 are provided. The report also includes an assessment of environmental and socioeconomic impacts of NPR-4 development.

The oil and gas resource estimates for the Beaufort Sea that form the basis of this report are contained in Geological Estimates of Undiscovered Oil and Gas Resources in the United States (Miller et al., 1975) which provides the most current U.S. Geological Survey estimates.

Energy and Mineral Resources of Alaska and the Impact of Federal Land Policies on their Availability (Klein and others, 1974) is one of several studies completed by the Alaska Division of Geological and Geophysical Surveys on the state’s oil and gas resources. This report provides estimates, in graphic and tabular form, on speculative petroleum resources for onshore and offshore sedimentary basins. The resource data are also broken down into land ownership categories and current land uses. For the Beaufort Sea Province, the state’s estimates of speculative oil and gas resources are lower than those of the U.S. Geological Survey.

More recently, the Alaska Department of Natural Resources (1977) has published A Study of State Petroleum Leasing Methods and Possible Alternatives, which contains an economic, historic and geographic evaluation of leasing methods and criteria.

Literature on Arctic petroleum technology is reviewed in Section 1.3.1.1.